NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

Tab Number	Request
49	(26) As to a subsidiary as referred to in (25) above, in lieu of duplicate copies of documentation required by Puc 1604.01(a)(5), (6), (11), (16), and (17), a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service (questions repeated below);
49	(26.05) Detailed list of charitable contributions charged in the test year showing donee and the amount according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all contributions shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all contributions of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all contributions of $2,500 and more shall be reported; d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all contributions of $5,000 and more shall be reported; and e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution;
49	(26.06) List of advertising charged in the test year above the line showing expenditure by media and by subject matter according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all expenditures shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all expenditures of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all expenditures of $2,500 and more shall be reported; and d. If the utility's annual gross reveneus are $100,000,000 or are in excess of $100,000,000, all expenditures of $5,000 and more shall be reported;
49	(26.11) Detailed list of all membership fees, dues, donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all membership fees, dues and donations shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all membership fees, dues and donations of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all membership fees, dues and donations of $2,500 and more shall be reported; and d. If the utility's annual gross reveneus are $100,000,000 or are in excess of $100,000,000, all membership fees, dues and donations of $5,000 and more shall be reported;

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(1) The utility's internal financial reports for the following periods:

a. For the first and last month of the test year;

b. For the entire test year; and

c. For the 12 months or 5 quarters prior to the test year;

Response:

Please find attached internal financial reports (balance sheets and income statements) for the above requested periods. The balance sheets are for the combined company Northern Utilities, Inc. The income statements are for the New Hampshire division of Northern Utilities, Inc.

	December 2009	January 2010	December 2010
ASSETS			
UTILITY PLANT			
Utility Plant (101-106, 114)	$222,580,042.40	$220,903,794.97	$250,797,088.03
Construction Work in Progress (107)	14,407,231.64	15,143,034.28	4,906,708.53
Total Utility Plant	236,987,274.04	236,046,829.25	255,703,796.56
Less: Accum. Depr. & Amort (108-111,115)	79,934,923.52	80,546,605.67	85,248,678.18
Net Utility Plant	157,052,350.52	155,500,223.58	170,455,118.38
OTHER PROPERTY & INVEST			
Nonutility prop less depr (121)	2,456,217.69	2,456,217.69	2,468,520.19
Accum Amort - Non Utility (122)	(1,799,438.92)	(1,820,795.92)	(1,950,748.86)
Other investments (124)	1,584.00	1,584.00	1,584.00
Total other prop. & invest.	658,362.77	637,005.77	519,355.33
CURRENT ASSETS			
Cash (131)	(191,465.41)	218,621.02	(195,182.62)
Special Deposits (132-134)	50,000.00	50,000.00	50,000.00
Working Funds (135)	2,200.00	2,200.00	2,000.00
Margin Deposit (136)	2,916,460.30	3,004,830.68	1,493,183.33
Accounts Receivable (142)	11,177,013.51	22,187,713.11	13,955,797.46
Other Accounts Receivable (143)	12,081.02	10,126.99	816,450.81
(Less) Accum. Prov. for Uncoll. Acct (144,260)	(451,012.30)	(670,777.44)	(438,102.00)
A/R from assoc, comp (146)	2,745,894.82	139,156.20	701,862.24
Plant Material & Operating Supplies (154)	1,061,203.15	1,066,763.19	1,156,295.14
Stores Expenses Undistributed (163)	38,377.30	77,294.91	65,425.44
Inventory (164)	994,686.68	714,501.59	884,123.44
Prepayments (165)	1,035,001.63	1,185,708.69	1,304,060.34
Accrued revenues (173)	2,722,392.64	2,631,013.23	4,177,320.21
Price Risk Asset (173 & 175)	2,229,540.00	2,111,730.00	836,660.00
Misc. current assets (171-174)	13,503,856.85	11,516,778.47	10,032,223.09
Total Current Assets	37,846,230.19	44,245,660.64	34,842,116.88
DEFERRED DEBITS			
Unamortized Debt Expense (181)	734,199.60	671,762.86	962,392.57
Other Regulatory Assets (182)	13,353,953.00	14,126,092.02	15,425,529.97
Prel. Survey & Inv. Chgs (183)	178,489.21	203,887.71	255,066.28
Clearing Accounts (184)	278,099.88	560,783.18	99,930.15
Misc. Deferred Debits (186)	12,351,895.82	13,557,004.84	10,324,994.40
Unrecovered Gas Costs (191)	9,500,700.74	5,676,242.17	14,455,146.32
Total Deferred Debits	36,397,338.25	34,795,772.78	41,523,059.69
TOTAL ASSETS	$231,954,281.73	$235,178,662.77	$247,339,650.28

	December 2009	January 2010	December 2010
LIABILITIES AND CAPITAL			
PROPRIETARY CAPITAL			
Common stock issued (201)	$1,000.00	$1,000.00	$1,000.00
Other Paid-In Captial (208-211)	65,699,000.00	65,699,000.00	73,199,000.00
Retained earnings (216)	1,743,856.28	3,088,067.70	(672,234.29)
Total proprietary capital	67,443,856.28	68,788,067.70	72,527,765.71
LONG TERM DEBT			
Other long-term debt (224)	80,000,000.00	80,000,000.00	105,000,000.00
Total long-term debt	80,000,000.00	80,000,000.00	105,000,000.00
CURRENT LIABILITIES			
Accounts payable (232)	17,877,466.76	19,429,609.44	19,803,252.19
Notes Payable to Associated Co. (233)	42,844,239.29	45,164,197.93	29,050,169.51
A/P to assoc. co's (234)	4,055,076.26	2,399,849.22	3,457,986.50
Customer deposits (235)	1,811,181.02	1,807,362.90	1,357,979.14
Taxes accrued (236)	1,161,429.79	3,602,686.04	11,543.80
Interest accrued (237)	463,454.28	958,870.94	943,948.88
Div. declared (238)	1,766,000.00	0.00	620,000.00
Tax Collections Payable (241)	(1,535.87)	75,383.87	1,146,277.72
Misc current liabilities (242)	1,189,105.39	919,391.82	1,064,000.83
Price Risk Liability (244)	2,309,230.00	2,248,430.00	1,019,890.00
Total current liabilities	73,475,646.92	76,605,782.16	58,475,048.57
DEFERRED CREDITS			
Cust. adv. for const. (252)	466,967.49	466,967.49	466,967.49
Other deferred credits (253)	7,200,109.11	7,964,408.00	11,665,385.29
Other regulatory liabilities (254)	2,346,926.09	2,345,530.09	708,650.51
Accum def. ITC (255)	92,483.83	90,446.83	68,039.83
Accum. def. inc taxes (283)	928,292.01	(1,082,539.50)	(1,572,207.12)
Total deferred credits	11,034,778.53	9,784,812.91	11,336,836.00
TOTAL LIABILITIES AND CAPITAL	$231,954,281.73	$235,178,662.77	$247,339,650.28

	YTD December 2009	MTD January 2010	MTD December 2010	YTD December 2010
OPERATING REVENUES				
Sales:				
Residential (480)	$26,214,618.02	$4,791,238.40	$3,097,302.29	$23,228,028.29
General Service (481)	29,527,453.49	4,906,544.86	2,878,358.14	22,503,855.22
Sales for Resale (483)	475,888.74	2,038,259.29	1,189,701.26	8,360,618.97
Other Sales (495)	(4,820,123.46)	(1,906,930.29)	791,803.94	3,415,436.03
Total Sales (Non External Supplier)	51,397,836.79	9,829,112.26	7,957,165.63	57,507,938.51
Other Operating Revenues:				
Late Charge (487)	171,623.25	13,520.05	4,535.87	123,278.97
Misc. Service Revenues (488)	810,465.43	75,525.40	119,720.15	920,096.37
Firm Transport Revenues (484, 489) (External S	4,745,322.07	711,420.54	654,824.25	4,894,187.21
Other Revenues	156,366.72	22,075.63	20,722.28	(3,384,604.87)
Total Other Operating Revenues	5,883,777.47	822,541.62	799,802.55	2,552,957.68
TOTAL OPERATING REVENUES	57,281,614.26	10,651,653.88	8,756,968.18	60,060,896.19
OPERATING EXPENSES				
Operation & Maint. Expenses:				
Production (710-813)	35,934,005.13	7,532,580.56	5,464,117.66	39,196,008.19
Transmission (850-857)	20,723.77	1,241.99	2,071.24	31,504.31
Distribution (870-894) (586)	3,212,948.85	295,881.70	139,149.34	3,082,543.96
Cust. Accounting (901-905)	905,376.85	234,364.38	140,294.45	1,821,527.73
Cust. Service & Info (906-910)	715,120.47	85,136.90	133,525.78	915,202.56
Admin. & General (920-935)	3,222,561.04	442,404.87	95,868.63	4,203,508.47
Total O & M Expenses	44,010,736.11	8,591,610.40	5,975,027.10	49,250,295.22
Other Operating Expenses:				
Deprtn. & Amort. (403-407)	3,833,814.25	346,373.28	400,126.59	4,244,804.65
Taxes-Other Than Inc. (408)	1,298,496.36	123,353.66	147,576.83	1,648,288.06
Federal Income Tax (409)	1,394,023.00	1,045,253.00	(673,335.15)	(1,739,140.81)
State Franchise Tax (409)	608,752.00	285,765.00	(140,113.69)	(430,436.78)
Def. Income Taxes (410,411)	(53,844.00)	(804,252.00)	1,576,141.63	2,750,647.06
Total Other Operating Expenses	7,081,241.61	996,492.94	1,310,396.21	6,474,162.18
TOTAL OPERATING EXPENSES	51,091,977.72	9,588,103.34	7,285,423.31	55,724,457.40
NET UTILITY OPERATING INCOME	6,189,636.54	1,063,550.54	1,471,544.87	4,336,438.79
OTHER INCOME & DEDUCTIONS				
Other Income:				
Other (415- 421)	121,827.91	9,562.44	21,336.56	185,479.90
Other Income Deduc. (425, 426)	63,167.07	6,639.15	22,069.38	97,467.72
Taxes Other than Income Taxes:				
Income Tax, Other Inc & Ded	23,236.00	1,158.00	(290.27)	34,861.66
Net Other Income & Deductions	35,424.84	1,765.29	(442.55)	53,150.52
GROSS INCOME	6,225,061.38	1,065,315.83	1,471,102.32	4,389,589.31
Interest Charges (427 - 432)	3,314,691.88	268,632.57	310,759.30	3,533,123.38
NET INCOME	$2,910,369.50	$796,683.26	$1,160,343.02	$856,465.93

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(2) Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;

Response:

Northern Utilities, Inc. does not make an annual report to stockholders. Please see response to Request No. 25.02 for Unitil Corporation's annual reports to stockholders for the most recent five years.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(3) Federal income tax reconciliation for the test year.

Response:

Please see the attached federal income tax reconciliation for Northern Utilities New Hampshire Division for the test year.

PUC 1604.01(a)(3)
Attachment 1

Northern Utilities, Inc. New Hampshire Division

	2010
Statutory Federal Income Tax Rate	34%
Income Tax Effects of:	
State income taxes - Net of Federal Benefit	6%
Utility Plant Differences	0%
Tax Credits and Other, net	2%
Effective Income Tax Rate	42%

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(4) Detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;

Response:

Please refer to the computation of Gross-Up Factor for Revenue Requirement, attached.

NORTHERN UTILITIES, INC NEW HAMPSHIRE DIVISION
COMPUTATION OF GROSS-UP FACTOR FOR REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2010

LINE NO	DESCRIPTION	RATE	AMOUNT
1	Revenue		1.0000
2	State Income Tax	8.50%	0.0850
3	Subtotal taxable income - Federal		0.9150
4	Federal Income Tax	35.00%	0.3203
5	Net Operating Income		0.5948
6	Gross-up Factor (1/Line 5)		1.6814

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(5) Detailed list of charitable contributions charged in the test year showing donee and the amount according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all contributions shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all contributions of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all contributions of $2,500 and more shall be reported;
d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all contributions of $5,000 and more shall be reported; and
e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution;;

Response:

Please see attached list of charitable contributions. These contributions were all charged below the line.

NORTHERN UTILITIES, INC.
LIST OF CHARITABLE CONTRIBUTIONS
1/1/2010 - 12/31/2010

Charitable Contributions in excess of $2,500

ORGANIZATION		AMOUNT
UNITED WAY OF THE GTR SEACOAST	$	2,500.00
WILDCAT SPORTS PROPERTIES		5,940.00
Grand Total	$	8,440.00

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(6) List of advertising charged in the test year above the line showing expenditure by media and by subject matter according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all expenditures shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all expenditures of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all expenditures of $2,500 and more shall be reported; and
d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all expenditures of $5,000 and more shall be reported;

Response:

There are no expenses in this category that reach the $2,500 threshold which applies to Northern Utilities, Inc. All advertising was charged below the line.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(7) The utility's most recent cost of service study.

Response:

The Company cost of service study is attached to the testimony of David Chong.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(8) The utility's most recent construction budget.

Response:

See table below of Northern Utilities, New Hampshire division's most recently approved construction budget for 2011.

Northern Utilities NH
Capital Budget 2011

Description	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure
Blankets:Gas	2,546,314	-	2,546,314
Communications:Gas	16,557	-	16,557
Distribution:Gas	6,239,422	-	6,239,422
Tools, Shop, Garage:Gas	33,026	-	33,026
Office:Gas	9,000	-	9,000
Transportation:Gas	5	-	5
Gas Totals:	8,844,324	-	8,844,324
Blankets:Water Heater	110,446	-	110,446
Hotwater Totals:	110,446	-	110,446
Structures:General	18,000	-	18,000
General/Common Totals:	18,000	-	18,000
Totals:	**$8,972,770**	**$ -**	**$8,972,770**

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(9) The utility's chart of accounts, if different from the uniform system of accounts established by the commission as part of PUC 300, PUC 400, PUC 500, PUC 600 and PUC 700;

Response:

See attached Chart of Accounts Report.

Account Code	Description	Type	Status
304000001010000	NH GAS PLANT IN SERVICE	Assets	Active
305000001010000	ME GAS PLANT IN SERVICE	Assets	Active
304000001050000	PROPERTY HELD FOR FUTURE USE - NH	Assets	Active
305000001050000	PROPERTY HELD FOR FUTURE USE - ME	Assets	Active
304000001050100	RAC RECOVERY - NH	Assets	Active
305000001050100	RAC RECOVERY - ME	Assets	Active
304000001060000	GS CMPL CNST NT CLSS - NH	Assets	Active
305000001060000	GS CMPL CNST NT CLSS - ME	Assets	Active
304000001060100	CAPITALIZE NU PROJECTS-NH	Assets	Active
305000001060100	CAPITALIZE NU PROJECTS-ME	Assets	Active
304000001070000	GAS CONST IN PROGRESS - NH	Assets	Active
305000001070000	GAS CONST IN PROGRESS - ME	Assets	Active
304000001070400	CONST IN PROGRESS - EQUIP-NH	Assets	Active
305000001070400	CONST IN PROGRESS - EQUIP - ME	Assets	Active
304000001079000	CONST WORK IN PROGRESS-CONST (GA)	Assets	Active
305000001079000	CONST WORK IN PROGRESS-CONST (GA)	Assets	Active
304000001080100	ACCUM DEPR GENERAL PLANT - NH	Assets	Active
305000001080100	ACCUM DEPR GENERAL PLANT - ME	Assets	Active
304000001080101	GAS GEN RETIREMENTS - NH	Assets	Active
305000001080101	GAS GEN RETIREMENTS - ME	Assets	Active
304000001080102	GAS GEN SALVAGE - NH	Assets	Active
305000001080102	GAS GEN SALVAGE - ME	Assets	Active
304000001080103	GAS GEN COST OF REMOVAL - NH	Assets	Active
305000001080103	GAS GEN COST OF REMOVAL - ME	Assets	Active
304000001080104	WATER HEATER SALVAGE - NH	Assets	Active
305000001080104	WATER HEATER SALVAGE - ME	Assets	Active
304000001110500	ACCUM AMORT COMPUTER SW	Assets	Active
305000001110500	ACCUM AMORT COMPUTER SW	Assets	Active
304000001110501	COMPUTER SW RETIREMENT	Assets	Active
305000001110501	COMPUTER SW RETIREMENT	Assets	Active
304000001140000	GROSS PLANT ACQUISITION ADJ	Assets	Active
305000001140000	GROSS PLANT ACQUISITION ADJ	Assets	Active
304000001140100	GROSS PAA - UNREGULATED	Assets	Active
305000001140100	GROSS PAA - UNREGULATED	Assets	Active
304000001150000	ACCUMULATED AMORTIZATION - PAA - NH	Assets	Active
305000001150000	ACCUMULATED AMORTIZATION - PAA - ME	Assets	Active
305000001210000	NON UTILITY PROPERTY - ME	Assets	Active
305000001220000	NON UTILITY RESERVE - ME	Assets	Active
305000001220001	NON UTILITY RETIREMENT	Assets	Active
305000001220002	NON UTILITY SALVAGE	Assets	Active
305000001220003	NON UTILITY COST OF REMOVAL	Assets	Active
300000001230000	INVEST IN ASSOC COMP	Assets	Active
304000001240000	OTHER INVESTMENTS - NH	Assets	Active
305000001240000	OTHER INVESTMENTS - ME	Assets	Active
300000001310000	CASH - REMITTANCE	Assets	Active
304000001310000	CASH - NH	Assets	Active
304500001310000	CASH - EXTERNAL SUPPLIER - NH	Assets	Active
305000001310000	CASH - ME	Assets	Active
305500001310000	CASH - EXTERNAL SUPPLIER - ME	Assets	Active
300000001310001	CASH - SUSPENSE	Assets	Active
304000001310001	CASH SUSPENSE - NH	Assets	Active
305000001310001	CASH SUSPENSE - ME	Assets	Active
304000001310002	CASH-SUPPLY	Assets	Active
305000001310002	CASH-SUPPLY	Assets	Active
305000001310099	CASH - ME	Assets	Active
302500001310100	CASH - SUPPLIER REFUND	Assets	Active
300000001311000	CASH - GENERAL FUNDS #4048	Assets	Active
300000001312000	CASH - CONTROL DISBURSEMENT	Assets	Active
300000001314000	CASH - CASHPOOL	Assets	Active
300000001340000	OTHER SPECIAL DEPOSITS	Assets	Active
304000001350000	CASH - WORKING FUNDS - NH	Assets	Active
305000001350000	CASH - WORKING FUNDS - ME	Assets	Active
304000001350099	CASH - WORKING FUNDS- NH	Assets	Active

Account Code	Description	Type	Status
304000001360000	MARGIN DEPOSIT	Assets	Active
305000001360000	MARGIN DEPOSIT - NH	Assets	Active
304000001410000	N/R-LAFUT - NH	Assets	Active
305000001410000	NOTES RECEIVABLE - ME	Assets	Active
304000001420000	A/R - OTHER - NH	Assets	Active
305000001420000	A/R - OTHER - ME	Assets	Active
304000001420100	A/R- SALES	Assets	Active
304500001420100	EXT SUPPLIER 1 - A/R	Assets	Active
305000001420100	A/R- SALES	Assets	Active
305500001420100	EXT SUPPLIER 1 - A/R	Assets	Active
304000001420101	A/R SALES SUSPENSE - NH	Assets	Active
305000001420101	A/R SALES SUSPENSE - ME	Assets	Active
304000001420102	A/R- SALES - COG	Assets	Active
304500001420102	EXT SUPPLIER 1 - REVENUE	Assets	Active
305000001420102	A/R- SALES - COG	Assets	Active
305500001420102	EXT SUPPLIER 1 - REVENUE	Assets	Active
304000001420200	A/R MANUAL ENTRIES - NH	Assets	Active
304500001420200	EXT SUPPLIER GLOBAL - A/R	Assets	Active
305000001420200	A/R MANUAL ENTRIES- ME	Assets	Active
305500001420200	EXT SUPPLIER GLOBAL - A/R	Assets	Active
304500001420202	EXT SUPPLIER GLOBAL - REVENUE	Assets	Active
305500001420202	EXT SUPPLIER GLOBAL - REVENUE	Assets	Active
304000001420300	A/R SUNDRY	Assets	Active
304500001420300	EXT SUPPLIER METROMEDIA - A/R	Assets	Active
305000001420300	A/R SUNDRY	Assets	Active
305500001420300	EXT SUPPLIER METROMEDIA - A/R	Assets	Active
304000001420301	A/R SUNDRY - SUSPENSE	Assets	Active
305000001420301	A/R SUNDRY - SUSPENSE	Assets	Active
304000001420302	A/R MISC ACCRUALS	Assets	Active
304500001420302	EXT SUPPLIER METROMEDIA - REVENUE	Assets	Active
305000001420302	A/R MISC ACCRUALS - ME	Assets	Active
305500001420302	EXT SUPPLIER METROMEDIA - REVENUE	Assets	Active
304500001420400	EXT SUPPLIER SHELL - A/R	Assets	Active
305500001420400	EXT SUPPLIER SHELL - A/R	Assets	Active
304500001420402	EXT SUPPLIER SHELL - REVENUE	Assets	Active
305500001420402	EXT SUPLLIER SHELL - REVENUE	Assets	Active
304000001420404	A/R REIMBURSABLE PROJECTS - NH	Assets	Active
305000001420404	A/R REIMBURSABLE PROJECTS - ME	Assets	Active
304500001420500	EXT SUPPLIER SPRAGUE - A/R	Assets	Active
305500001420500	EXT SUPPLIER SPRAGUE - A/R	Assets	Active
304500001420502	EXT SUPPLIER SPRAGUE - REVENUE	Assets	Active
305500001420502	EXT SUPPLIER SPRAGUE - REVENUE	Assets	Active
304500001420600	EXT SUPPLIER SANTA BUCKLEY - A/R	Assets	Active
304500001420602	EXT SUPPLIER SANTA BUCKLEY - REVENUE	Assets	Active
304500001420800	EXT SUPPLIER A/R - SOUTH JERSEY	Assets	Active
305500001420800	EXT SUPPLIER A/R - SOUTH JERSEY	Assets	Active
304500001420802	EXT SUPPLIER REVENUE - SOUTH JERSEY	Assets	Active
305500001420802	EXT SUPPLIER SUPPLIER REVENUE - SOUTH JERSEY	Assets	Active
304500001420900	EXT SUPPLIER A/R - GLACIAL	Assets	Active
305500001420900	EXT SUPPLIER A/R - GLACIAL	Assets	Active
304500001420902	EXT SUPPLIER REVENUE - GLACIAL	Assets	Active
305500001420902	EXT SUPPLIER REVENUE - GLACIAL	Assets	Active
304000001425300	A/R BONE-VEBA MGMT TRUST	Assets	Active
305000001425300	A/R BONE-VEBA MGMT TRUST	Assets	Active
304000001425400	A/R BONE-VEBA UNION TRUST	Assets	Active
305000001425400	A/R BONE-VEBA UNION TRUST	Assets	Active
304000001430000	A/R - OTHER - NH	Assets	Active
305000001430000	A/R - OTHER - ME	Assets	Active
305000001430073	ACCOUNTS RECEIVABLE OTHER - ME EERA	Assets	Active
300000001430100	A/R - MISCELLANEOUS	Assets	Active
304000001430303	A/R DRUG SUBSIDY - NH	Assets	Active
305000001430303	A/R DRUG SUBSIDY - ME	Assets	Active
304000001430400	EASTHAMPTON LNG PROJ - TENN - NH	Assets	Active
305000001430400	A/R ME SALES TAX PRIOR PERIOD COLLECTION	Assets	Active

Account Code	Description	Type	Status
300000001432300	A/R EMPLOYEES - GAS & ELEC.	Assets	Active
300000001432400	A/R EMPLOYEES - MERCHANDISE	Assets	Active
300000001432500	A/R CUST PURCH - WATER HEATERS	Assets	Active
304000001432500	A/R CUST PURCH- WATER HEATERS	Assets	Active
305000001432500	A/R CUST PURCH- WATER HEATERS	Assets	Active
300000001432700	A/R EMPLOYEE PC PURCHASES	Assets	Active
300000001432800	A/R - NON WATER HEATER REPAIRS	Assets	Active
300000001433000	A/R FOR CONSTRUCTION PROJECTS	Assets	Active
304000001436600	A/R-3RD PARTY SALES & TRANS	Assets	Active
300000001440000	ALLOW FOR DOUBTFUL ACCTS - GAS	Assets	Active
304000001440000	ALLOW FOR DOUBTFUL ACCTS (BEG BAL) - DISTRIBUTION	Assets	Active
305000001440000	ALLOW FOR DOUBTFUL ACCTS (BEG BAL) - DISTRIBUTION	Assets	Active
305000001440001	R-1 NU CONVERTED WRITE OFFS	Assets	Active
305000001440002	R-2 NU CONVERTED WRITE OFFS	Assets	Active
300000001440003	ALLOW FOR DOUBTFUL ACCTS - GAS SUPPLY	Assets	Active
304000001440005	R-5 NU CONVERTED WRITE OFFS	Assets	Active
304000001440006	R-6 NU CONVERTED WRITE OFFS	Assets	Active
304000001440010	R-10 NU CONVERTED WRITE OFFS	Assets	Active
304000001440011	R-11 NU CONVERTED WRITE OFFS	Assets	Active
300000001440027	ALLOW FOR DOUBTFUL ACCTS - NON-DIST	Assets	Active
304000001440027	ALLOW FOR DOUBTFUL ACCTS - NON-DIST	Assets	Active
305000001440027	ALLOW FOR DOUBTFUL ACCTS - NON-DIST	Assets	Active
304000001440040	G-40 NU CONVERTED WRITE OFFS	Assets	Active
305000001440040	G-40 NU CONVERTED WRITE OFFS	Assets	Active
304000001440041	G-41 NU CONVERTED WRITE OFFS	Assets	Active
305000001440041	G-41 NU CONVERTED WRITE OFFS	Assets	Active
304000001440042	G-42 NU CONVERTED WRITE OFFS	Assets	Active
305000001440042	G-42 NU CONVERTED WRITE OFFS	Assets	Active
304000001440050	G-50 NU CONVERTED WRITE OFFS	Assets	Active
305000001440050	G-50 NU CONVERTED WRITE OFFS	Assets	Active
304000001440051	G-51 NU CONVERTED WRITE OFFS	Assets	Active
305000001440051	G-51 NU CONVERTED WRITE OFFS	Assets	Active
304000001440052	G-52 NU CONVERTED WRITE OFFS	Assets	Active
305000001440052	G-52 NU CONVERTED WRITE OFFS	Assets	Active
304000001440060	SIMPLEX NU CONVERTED WRITE OFFS	Assets	Active
305000001440060	JJ NISSEN NU CONVERTED WRITE OFFS	Assets	Active
304000001440061	NAT GYPSUM NU CONVERTED WRITE OFFS	Assets	Active
305000001440061	NAVAL SHIPYARD NU CONVERTED WRITE OFFS	Assets	Active
304000001440062	FOSS NU CONVERTED WRITE OFFS	Assets	Active
300000001440100	ALLOW FOR DOUBTFUL ACCTS	Assets	Active
304000001440100	ALLOW FOR DOUBTFUL ACCTS - NH	Assets	Active
304000011440100	ALLOW FOR DOUBTFUL ACCTS	Assets	Active
304000021440100	ALLOW FOR DOUBTFUL ACCTS	Assets	Active
305000001440100	ALLOW FOR DOUBTFUL ACCTS - ME	Assets	Active
305000011440100	ALLOW FOR DOUBTFUL ACCTS	Assets	Active
305000021440100	ALLOW FOR DOUBTFUL ACCTS	Assets	Active
300000001440200	ALLOW FOR DOUBTFUL ACCTS - W/O - DISTR	Assets	Active
304000001440200	ALLOW FOR DOUBTFUL ACCTS - COM - NON CLASS SPECIFIC	Assets	Active
304000011440200	ALLOW FOR DOUBTFUL ACCTS - WIN - NON CLASS SPECIFIC	Assets	Active
304000021440200	ALLOW FOR DOUBTFUL ACCTS - SUM - NON CLASS SPECIFIC	Assets	Active
305000001440200	ALLOW FOR DOUBTFUL ACCTS - COM - NON CLASS SPECIFIC	Assets	Active
305000011440200	ALLOW FOR DOUBTFUL ACCTS - WIN - NON CLASS SPECIFIC	Assets	Active
305000021440200	ALLOW FOR DOUBTFUL ACCTS - SUM - NON CLASS SPECIFIC	Assets	Active
305000011440201	ALLOW FOR DOUBTFUL A/CS-W/O-R-1-DISTR-PEAK	Assets	Active
305000021440201	ALLOW FOR DOUBTFUL A/CS-W/O-R-1-DISTR-OFF PEAK	Assets	Active
305000031440201	ALLOW FOR DOUBTFUL A/CS-W/O-R-1-DISTR-NO SEASON	Assets	Active
305000011440202	ALLOW FOR DOUBTFUL A/CS-W/O-R-2-DISTR-PEAK	Assets	Active
305000021440202	ALLOW FOR DOUBTFUL A/CS-W/O-R-2-DISTR-OFF PEAK	Assets	Active
305000031440202	ALLOW FOR DOUBTFUL A/CS-W/O-R-2-DISTR-NO SEASON	Assets	Active
304000011440205	ALLOW FOR DOUBTFUL A/CS-W/O-R5-DISTR-PEAK	Assets	Active
304000021440205	ALLOW FOR DOUBTFUL A/CS-W/O-R5-DISTR-OFF PEAK	Assets	Active
304000031440205	ALLOW FOR DOUBTFUL A/CS-W/O-R5-DISTR-NO SEASON	Assets	Active
304000011440206	ALLOW FOR DOUBTFUL A/CS-W/O-R6-DISTR-PEAK	Assets	Active
304000021440206	ALLOW FOR DOUBTFUL A/CS-W/O-R6-DISTR-OFF PEAK	Assets	Active

Account Code	Description	Type	Status
304000031440206	ALLOW FOR DOUBTFUL A/CS-W/O-R6-DISTR-NO SEASON	Assets	Active
304000011440210	ALLOW FOR DOUBTFUL A/CS-W/O-R10-DISTR-PEAK	Assets	Active
304000021440210	ALLOW FOR DOUBTFUL A/CS-W/O-R10-DISTR-OFF PEAK	Assets	Active
304000031440210	ALLOW FOR DOUBTFUL A/CS-W/O-R10-DISTR-NO SEASON	Assets	Active
304000011440211	ALLOW FOR DOUBTFUL A/CS-W/O-R11-DISTR-PEAK	Assets	Active
304000021440211	ALLOW FOR DOUBTFUL A/CS-W/O-R11-DISTR-OFF PEAK	Assets	Active
304000031440211	ALLOW FOR DOUBTFUL A/CS-W/O-R11-DISTR-NO SEASON	Assets	Active
304000011440240	ALLOW FOR DOUBTFUL A/CS-W/O-G40-DISTR-PEAK	Assets	Active
304000021440240	ALLOW FOR DOUBTFUL A/CS-W/O-G40-DISTR-OFF PEAK	Assets	Active
304000031440240	ALLOW FOR DOUBTFUL A/CS-W/O-G40-DISTR-NO SEASON	Assets	Active
305000011440240	ALLOW FOR DOUBTFUL A/CS-W/O-G-40-DISTR-PEAK	Assets	Active
305000021440240	ALLOW FOR DOUBTFUL A/CS-W/O-G-40-DISTR-OFF PEAK	Assets	Active
305000031440240	ALLOW FOR DOUBTFUL A/CS-W/O-G-40-DISTR-NO SEASON	Assets	Active
304000011440241	ALLOW FOR DOUBTFUL A/CS-W/O-G41-DISTR-PEAK	Assets	Active
304000021440241	ALLOW FOR DOUBTFUL A/CS-W/O-G41-DISTR-OFF PEAK	Assets	Active
304000031440241	ALLOW FOR DOUBTFUL A/CS-W/O-G41-DISTR-NO SEASON	Assets	Active
305000011440241	ALLOW FOR DOUBTFUL A/CS-W/O-G-41-DISTR-PEAK	Assets	Active
305000021440241	ALLOW FOR DOUBTFUL A/CS-W/O-G-41-DISTR-OFF PEAK	Assets	Active
305000031440241	ALLOW FOR DOUBTFUL A/CS-W/O-G41 DISTR-NO SEASON	Assets	Active
304000011440242	ALLOW FOR DOUBTFUL A/CS-W/O-G42-DISTR-PEAK	Assets	Active
304000021440242	ALLOW FOR DOUBTFUL A/CS-W/O-G42-DISTR-OFF PEAK	Assets	Active
304000031440242	ALLOW FOR DOUBTFUL A/CS-W/O-G42-DISTR-NO SEASON	Assets	Active
305000011440242	ALLOW FOR DOUBTFUL A/CS-W/O-G-42-DISTR-PEAK	Assets	Active
305000021440242	ALLOW FOR DOUBTFUL A/CS-W/O-G-42-DISTR-OFF PEAK	Assets	Active
305000031440242	ALLOW FOR DOUBTFUL A/CS-W/O-G42DISTR-NO SEASON	Assets	Active
304000011440250	ALLOW FOR DOUBTFUL A/CS-W/O-G50-DISTR-PEAK	Assets	Active
304000021440250	ALLOW FOR DOUBTFUL A/CS-W/O-G50-DISTR-OFF PEAK	Assets	Active
304000031440250	ALLOW FOR DOUBTFUL A/CS-W/O-G50-DISTR-NO SEASON	Assets	Active
305000011440250	ALLOW FOR DOUBTFUL A/CS-W/O-G-50-DISTR-PEAK	Assets	Active
305000021440250	ALLOW FOR DOUBTFUL A/CS-W/O-G-50-DISTR-OFF PEAK	Assets	Active
305000031440250	ALLOW FOR DOUBTFUL A/CS-W/O-G-50-DISTR-NO SEASON	Assets	Active
304000011440251	ALLOW FOR DOUBTFUL A/CS-W/O-G51-DISTR-PEAK	Assets	Active
304000021440251	ALLOW FOR DOUBTFUL A/CS-W/O-G51-DISTR-OFF PEAK	Assets	Active
304000031440251	ALLOW FOR DOUBTFUL A/CS-W/O-G51 DISTR-NO SEASON	Assets	Active
305000011440251	ALLOW FOR DOUBTFUL A/CS-W/O-G-51-DISTR-PEAK	Assets	Active
305000021440251	ALLOW FOR DOUBTFUL A/CS-W/O-G-51-DISTR-OFF PEAK	Assets	Active
305000031440251	ALLOW FOR DOUBTFUL A/CS-W/O-G-51-DISTR-NO SEASON	Assets	Active
304000011440252	ALLOW FOR DOUBTFUL A/CS-W/O-G52-DISTR-PEAK	Assets	Active
304000021440252	ALLOW FOR DOUBTFUL A/CS-W/O-G52-DISTR-OFF PEAK	Assets	Active
304000031440252	ALLOW FOR DOUBTFUL A/CS-W/O-G52 DISTR-NO SEASON	Assets	Active
305000011440252	ALLOW FOR DOUBTFUL A/CS-W/O-G-52-DISTR-PEAK	Assets	Active
305000021440252	ALLOW FOR DOUBTFUL A/CS-W/O-G-52-DISTR-OFF PEAK	Assets	Active
305000031440252	ALLOW FOR DOUBTFUL A/CS-W/O-G-52-DISTR-NO SEASON	Assets	Active
304000011440260	ALLOW FOR DOUBTFUL A/CS-W/O-Simplex-DISTR-PEAK	Assets	Active
304000021440260	ALLOW FOR DOUBTFUL A/CS-W/O-Simplex-DISTR-OFF PEAK	Assets	Active
304000031440260	ALLOW FOR DOUBTFUL A/CS-W/O-SIMPLEX DISTR-NO SEASON	Assets	Active
305000011440260	ALLOW FOR DOUBTFUL A/CS-W/O-JJ Nissen-DISTR-PEAK	Assets	Active
305000021440260	ALLOW FOR DOUBTFUL A/CS-W/O-JJ Nissen-DISTR-OFF PEAK	Assets	Active
305000031440260	ALLOW FOR DOUBTFUL A/CS-W/O-JJ NISSEN-DISTR-NO SEASON	Assets	Active
304000011440261	ALLOW FOR DOUBTFUL A/CS-W/O-Nat Gypsum-DISTR-PEAK	Assets	Active
304000021440261	ALLOW FOR DOUBTFUL A/CS-W/O-Nat Gypsum-DISTR-OFF PEAK	Assets	Active
304000031440261	ALLOW FOR DOUBTFUL A/CS-W/O-NAT GYPSUM DISTR-NO SEASON	Assets	Active
305000011440261	ALLOW FOR DOUBTFUL A/CS-W/O-Naval Shipyard-DISTR-PEAK	Assets	Active
305000021440261	ALLOW FOR DOUBTFUL A/CS-W/O-Naval Shipyard-DISTR-OFF PEAK	Assets	Active
305000031440261	ALLOW FOR DOUBTFUL A/CS-W/O-NAVAL SHIPYARD-DISTR-NO SEASON	Assets	Active
304000011440262	ALLOW FOR DOUBTFUL A/CS-W/O-Foss-DISTR-PEAK	Assets	Active
304000021440262	ALLOW FOR DOUBTFUL A/CS-W/O-Foss-DISTR-OFF PEAK	Assets	Active
304000031440262	ALLOW FOR DOUBTFUL A/CS-W/O-FOSS DISTR-NO SEASON	Assets	Active
305000031440273	ALLOW FOR DOUBTFUL A/CS-W/O-POST 7-1-10 EERA-NO SEASON	Assets	Active
300000001440300	ALLOW FOR DOUBTFUL ACCTS - W/O - SPECIAL	Assets	Active
300000001440400	ALLOW FOR DOUBTFUL ACCTS - W/O - CGA - DS	Assets	Active
304000001440400	ALLOW FOR DOUBTFUL ACCTS - (BEG BAL) - NON DIST-NH	Assets	Active
305000001440400	ALLOW FOR DOUBTFUL ACCTS - (BEG BAL) - NON DIST-ME	Assets	Active
305000001440401	R-1 NU CONVERTED WRITE OFFS-NON DIST	Assets	Active

Account Code	Description	Type	Status
305000011440401	ALLOW FOR DOUBTFUL A/CS-W/O-R-1-NON DIST-PEAK	Assets	Active
305000021440401	ALLOW FOR DOUBTFUL A/CS-W/O-R-1-NON DIST-OFF PEAK	Assets	Active
305000001440402	R-2 NU CONVERTED WRITE OFFS-NON DIST	Assets	Active
305000011440402	ALLOW FOR DOUBTFUL A/CS-W/O-R-2-NON DIST-PEAK	Assets	Active
305000021440402	ALLOW FOR DOUBTFUL A/CS-W/O-R-2-NON DIST-OFF PEAK	Assets	Active
304000001440405	R-5 NU CONVERTED WRITE OFFS - NON DIST	Assets	Active
304000011440405	ALLOW FOR DOUBTFUL A/CS-W/O-R5-NON DIST-PEAK	Assets	Active
304000021440405	ALLOW FOR DOUBTFUL A/CS-W/O-R5-NON DIST-OFF PEAK	Assets	Active
304000011440406	ALLOW FOR DOUBTFUL A/CS-W/O-R6-NON DIST-PEAK	Assets	Active
304000021440406	ALLOW FOR DOUBTFUL A/CS-W/O-R6-NON DIST-OFF PEAK	Assets	Active
304000011440410	ALLOW FOR DOUBTFUL A/CS-W/O-R10-NON DIST-PEAK	Assets	Active
304000021440410	ALLOW FOR DOUBTFUL A/CS-W/O-R10-NON DIST-OFF PEAK	Assets	Active
304000011440411	ALLOW FOR DOUBTFUL A/CS-W/O-R11-NON DIST-PEAK	Assets	Active
304000021440411	ALLOW FOR DOUBTFUL A/CS-W/O-R11-NON DIST-OFF PEAK	Assets	Active
304000011440440	ALLOW FOR DOUBTFUL A/CS-W/O-G40-NON DIST-PEAK	Assets	Active
304000021440440	ALLOW FOR DOUBTFUL A/CS-W/O-G40-NON DIST-OFF PEAK	Assets	Active
305000001440440	G-40 NU CONVERTED WRITE OFFS-NON DIST	Assets	Active
305000011440440	ALLOW FOR DOUBTFUL A/CS-W/O-G-40-NON DIST-PEAK	Assets	Active
305000021440440	ALLOW FOR DOUBTFUL A/CS-W/O-G-40-NON DIST-OFF PEAK	Assets	Active
304000011440441	ALLOW FOR DOUBTFUL A/CS-W/O-G41-NON DIST-PEAK	Assets	Active
304000021440441	ALLOW FOR DOUBTFUL A/CS-W/O-G41-NON DIST-OFF PEAK	Assets	Active
305000011440441	ALLOW FOR DOUBTFUL A/CS-W/O-G-41-NON DIST-PEAK	Assets	Active
305000021440441	ALLOW FOR DOUBTFUL A/CS-W/O-G-41-NON DIST-OFF PEAK	Assets	Active
304000011440442	ALLOW FOR DOUBTFUL A/CS-W/O-G42-NON DIST-PEAK	Assets	Active
304000021440442	ALLOW FOR DOUBTFUL A/CS-W/O-G42-NON DIST-OFF PEAK	Assets	Active
305000011440442	ALLOW FOR DOUBTFUL A/CS-W/O-G-42-NON DIST-PEAK	Assets	Active
305000021440442	ALLOW FOR DOUBTFUL A/CS-W/O-G-42-NON DIST-OFF PEAK	Assets	Active
304000011440450	ALLOW FOR DOUBTFUL A/CS-W/O-G50-NON DIST-PEAK	Assets	Active
304000021440450	ALLOW FOR DOUBTFUL A/CS-W/O-G50-NON DIST-OFF PEAK	Assets	Active
305000001440450	G-50 NU CONVERTED WRITE OFFS-NON DIST	Assets	Active
305000011440450	ALLOW FOR DOUBTFUL A/CS-W/O-G-50-NON DIST-PEAK	Assets	Active
305000021440450	ALLOW FOR DOUBTFUL A/CS-W/O-G-50-NON DIST-OFF PEAK	Assets	Active
304000011440451	ALLOW FOR DOUBTFUL A/CS-W/O-G51-NON DIST-PEAK	Assets	Active
304000021440451	ALLOW FOR DOUBTFUL A/CS-W/O-G51-NON DIST-OFF PEAK	Assets	Active
305000011440451	ALLOW FOR DOUBTFUL A/CS-W/O-G-51-NON DIST-PEAK	Assets	Active
305000021440451	ALLOW FOR DOUBTFUL A/CS-W/O-G-51-NON DIST-OFF PEAK	Assets	Active
304000011440452	ALLOW FOR DOUBTFUL A/CS-W/O-G52-NON DIST-PEAK	Assets	Active
304000021440452	ALLOW FOR DOUBTFUL A/CS-W/O-G52-NON DIST-OFF PEAK	Assets	Active
305000011440452	ALLOW FOR DOUBTFUL A/CS-W/O-G-52-NON DIST-PEAK	Assets	Active
305000021440452	ALLOW FOR DOUBTFUL A/CS-W/O-G-52-NON DIST-OFF PEAK	Assets	Active
304000011440460	ALLOW FOR DOUBTFUL A/CS-W/O-Simplex-NON DIST-PEAK	Assets	Active
304000021440460	ALLOW FOR DOUBTFUL A/CS-W/O-Simplex-NON DIST-OFF PEAK	Assets	Active
305000011440460	ALLOW FOR DOUBTFUL A/CS-W/O-JJ Nissen-NON DIST-PEAK	Assets	Active
305000021440460	ALLOW FOR DOUBTFUL A/CS-W/O-JJ Nissen-NON DIST-OFF PEAK	Assets	Active
304000011440461	ALLOW FOR DOUBTFUL A/CS-W/O-Nat Gypsum-NON DIST-PEAK	Assets	Active
304000021440461	ALLOW FOR DOUBTFUL A/CS-W/O-Nat Gypsum-NON DIST-OFF PEAK	Assets	Active
305000011440461	ALLOW FOR DOUBTFUL A/CS-W/O-Naval Shipyard-NON DIST-PEAK	Assets	Active
305000021440461	ALLOW FOR DOUBTFUL A/CS-W/O-Naval Shipyard-NON DIST-OFF PEAK	Assets	Active
304000011440462	ALLOW FOR DOUBTFUL A/CS-W/O-Foss-NON DIST-PEAK	Assets	Active
304000021440462	ALLOW FOR DOUBTFUL A/CS-W/O-Foss-NON DIST-OFF PEAK	Assets	Active
300000001440500	ALLOW FOR DOUBTFUL ACCTS - RECOVERIES - DIST	Assets	Active
304000001440500	ALLOW FOR DOUBTFUL ACCTS - RECOVERIES - DIST	Assets	Active
305000001440500	ALLOW FOR DOUBTFUL ACCTS - RECOVERIES - DIST	Assets	Active
300000001440501	ALLOW FOR DOUBTFUL ACCTS - RECOVERIES - CGA	Assets	Active
304000001440501	ALLOW FOR DOUBTFUL ACCTS- RECOVERIES - CGA	Assets	Active
305000001440501	ALLOW FOR DOUBTFUL ACCTS- RECOVERIES - CGA	Assets	Active
304000001440700	ALLOW FOR DOUBTFUL ACCTS - CGA	Assets	Active
305000001440700	ALLOW FOR DOUBTFUL ACCTS - CGA	Assets	Active
304000001441000	EXT SUPPLIER 1 - W/O	Assets	Active
305000001441000	EXT SUPPLIER 1 - W/O	Assets	Active
305000001441200	ALLOW FOR DOUBTFUL ACCTS - W/O-ME SALES TAX	Assets	Active
300000001441500	ALLOW FOR DOUBTFUL ACCTS - W/O - ARREARS	Assets	Active
300000001441501	ALLOW FOR DOUBTFUL ACCTS - W/O - ARREARS	Assets	Active
304000001441600	ALLOW FOR DOUBTFUL ACCTS - SUNDRY	Assets	Active

Account Code	Description	Type	Status
305000001441600	ALLOW FOR DOUBTFUL ACCTS - SUNDRY	Assets	Active
304000001441601	ALLOW FOR DOUBTFUL ACCTS - W/O - SUNDRY	Assets	Active
305000001441601	ALLOW FOR DOUBTFUL ACCTS - W/O - SUNDRY	Assets	Active
304000001441620	ALLOW FOR DOUBTFUL ACCTS (BEG BAL) - SUNDRY	Assets	Active
305000001441620	ALLOW FOR DOUBTFUL ACCTS (BEG BAL) - SUNDRY	Assets	Active
304000001441700	ALLOW FOR DOUBTFUL A/CS-IG	Assets	Active
305000001441700	ALLOW FOR DOUBTFUL A/CS-IG	Assets	Active
300000001460110	A/R ASSOC COS - UES	Assets	Active
300000001460112	A/R ASSOC COS - USC	Assets	Active
300000001460113	A/R ASSOC COS - UPC	Assets	Active
300000001460114	A/R ASSOC COS - URC	Assets	Active
300000001460115	A/R ASSOC COS - UC	Assets	Active
300000001460120	A/R ASSOC COS - FGE	Assets	Active
300000001460121	A/R ASSOC COS - FEDCO	Assets	Active
300000001460124	A/R ASSOC COS - URI	Assets	Active
300000001460125	A/R ASSOC COS - UI	Assets	Active
300000001460126	A/R ASSOC COS - USOURCE	Assets	Active
300000001460133	A/R ASSOC COS - GSG	Assets	Active
300000001460600	A/R NISOURCE SHARED SERVICES	Assets	Active
300000001460800	A/R A7-NI Restricted Stk	Assets	Active
300000001510100	NATURAL GAS	Assets	Active
300000001517700	FUEL STOCK LIQ PROPANE	Assets	Active
300000001518100	FUEL STOCK LNG	Assets	Active
304000001540100	MATERIALS & SUPPLIES - NH	Assets	Active
305000001540100	MATERIALS & SUPPLIES - ME	Assets	Active
304000001550000	MERCHANDISE - NH	Assets	Active
305000001550000	MERCHANDISE - ME	Assets	Active
304000001630000	STORES EXP UNDISTRIBUTED - NH	Assets	Active
305000001630000	STORES EXP UNDISTRIBUTED - ME	Assets	Active
304000001630100	STOREROOM OPERATING EXPENSE - NH	Assets	Active
305000001630100	STOREROOM OPERATING EXPENSE - ME	Assets	Active
304000001630200	STOCK OVER & SHORT - NH	Assets	Active
305000001630200	STOCK OVER & SHORT - ME	Assets	Active
304000001630300	OBSOLETE STOCK - NH	Assets	Active
305000001630300	OBSOLETE STOCK - ME	Assets	Active
300000001640000	GAS INVENTORY- WEIGHTED AVG	Assets	Active
304000001640400	INVENTORY - SALEM PROPANE	Assets	Active
305000001640400	INVENTORY - LIQUID PROPANE	Assets	Active
304000001640600	INVENTORY - SALEM PROPANE	Assets	Active
304000001641400	INVENTORY - NAT GAS FSS-1 (TETCO 400513)	Assets	Active
304000001641500	INVENTORY - NAT GAS SS1-400193 - TETCO	Assets	Active
304000001641600	INVENTORY - NAT GAS SSNE (TENN GAS/TGP)	Assets	Active
305000001645200	INVENTORY - LIQUIFIED NATURAL GAS	Assets	Active
304000001650000	PREPAID INSURANCE AND LEASES - NH	Assets	Active
305000001650000	PREPAID INSURANCE AND LEASES - ME	Assets	Active
304000001650100	PREPAID PROPERTY INSURANCE	Assets	Active
305000001650100	PREPAID PROPERTY INSURANCE	Assets	Active
304000001650101	PREPAID INJURIES & DAMAGES INS	Assets	Active
305000001650101	PREPAID INJURIES & DAMAGES INS	Assets	Active
300000001650108	MISCELLANEOUS PREPAIDS	Assets	Active
304000001650200	PREPAID NH PUC ASSESSMENT	Assets	Active
305000001650200	PREPAID ME PUC ASSESSMENT	Assets	Active
304000001650401	FASB 87 - PREPAID PENSION - NH	Assets	Active
305000001650401	FASB 87 - PREPAID PENSION - ME	Assets	Active
304000001650800	PREPAID DPU ASSESSMENT	Assets	Active
305000001650800	PREPAID DPU ASSESSMENT	Assets	Active
300000001651000	RETIREE LIFE INSURANCE	Assets	Active
304000001651100	PREPAID PROPERTY TAX - NH	Assets	Active
305000001651100	PREPAID PROPERTY TAX - ME	Assets	Active
300000001651200	PREPAID POSTAGE	Assets	Active
304000001651200	PREPAID POSTAGE	Assets	Active
305000001651200	PREPAID POSTAGE	Assets	Active
304000001651300	PREPAID GAS PURCHASE	Assets	Active
305000001651300	PREPAID GAS PURCHASE	Assets	Active

Account Code	Description	Type	Status
300000001651400	PREPAID REVOLVER	Assets	Active
304000001651900	OTHER MISC PREPAYMENT - NH	Assets	Active
305000001651900	OTHER MISC PREPAYMENT - ME	Assets	Active
304000001652000	PREPAID GAS IRP PROGRAM - NH	Assets	Active
305000001652000	PREPAID GAS IRP PROGRAM - ME	Assets	Active
304000001653000	PREPAID OPEB - UNION - NH	Assets	Active
305000001653000	PREPAID OPEB - UNION - ME	Assets	Active
304000001653500	PREPAID OPEB - NON UNION - NH	Assets	Active
305000001653500	PREPAID OPEB - NON UNION - ME	Assets	Active
300000001710000	INTEREST OR DIVIDENDS RECEIVABLE	Assets	Active
304000001710000	INTEREST OR DIVIDENDS RECEIVABLE - NH	Assets	Active
305000001710000	INTEREST OR DIVIDENDS RECEIVABLE - ME	Assets	Active
300000001720000	RENTS RECEIVABLE	Assets	Active
304000001730000	UNBILLED REVENUE - NH	Assets	Active
305000001730000	UNBILLED REVENUE - ME	Assets	Active
304000001730100	ACCRUED REVENUE MISC- NH	Assets	Active
300000001730102	NOT BILLED REVENUE	Assets	Active
304000001730200	Interruptible Margin Sharing - NH	Assets	Active
305000001730200	Interruptible Margin Sharing - ME	Assets	Active
304000001730500	ACCRUED REV ECS - NH	Assets	Active
305000001730500	ACCRUED REV - ERC - ME	Assets	Active
304000001730600	ACCRUED REVENUE - CYCLE 22	Assets	Active
305000001730600	ACCRUED REVENUE - CYCLE 22	Assets	Active
304000001733000	PRICE RISK - CURRENT - NH	Assets	Active
305000001733000	PRICE RISK - CURRENT - ME	Assets	Active
304000001733100	ERC SITE COSTS - CURRENT - NH	Assets	Active
305000001733100	ERC SITE COSTS - CURRENT - ME	Assets	Active
304000001734101	ACCRUED REVENUE EE - LI - NH	Assets	Active
305000001734101	ACCRUED REVENUE EE - LI - ME	Assets	Active
304000001734102	ACCRUED REVENUE EE - R - NH	Assets	Active
305000001734102	ACCRUED REVENUE EE - R - ME	Assets	Active
304000001734106	ACCRUED REVENUE EE - CI - NH	Assets	Active
305000001734106	ACCRUED REVENUE EE - CI - ME	Assets	Active
304000001740100	MICHON EXCHANGE GAS RECEIVABLE - NH	Assets	Active
305000001740100	MICHON EXCHANGE GAS RECEIVABLE - ME	Assets	Active
304000001740500	VACATION ACCRUAL - NH	Assets	Active
305000001740500	VACATION ACCRUAL - ME	Assets	Active
304000001742500	INVENTORY - EXCHANGE GAS WASHINGTON 10B	Assets	Active
304000001750000	INTER DIVISION TRANSFER - NH	Assets	Active
305000001750000	INTER DIVISION TRANSFER - ME	Assets	Active
304000001750100	PRICE RISK ASSET - CURRENT - NH	Assets	Active
305000001750100	PRICE RISK ASSET - CURRENT - ME	Assets	Active
304000001750200	PRICE RISK ASSET - NON CURRENT -NH	Assets	Active
305000001750200	PRICE RISK ASSET - NON CURRENT -ME	Assets	Active
304000001750900	DEF OFF-PEAK COMMODITY CGA	Assets	Active
305000001750900	DEF OFF-PEAK COMMODITY CGA	Assets	Active
305000001750901	ACCRUED REVENUE - EERA - ME - LOW INCOME	Assets	Active
305000001750902	ACCRUED REVENUE - EERA - ME - RESIDENTIAL	Assets	Active
305000001750906	ACCRUED REVENUE - EERA - ME - SMALL C&I	Assets	Active
304000001751000	DEF OFF-PEAK DEMAND CGA	Assets	Active
305000001751000	DEF OFF-PEAK DEMAND CGA	Assets	Active
304000001751900	DEF PEAK COMMODITY CGA	Assets	Active
305000001751900	DEF PEAK COMMODITY CGA	Assets	Active
304000001752000	DEF PEAK DEMAND CGA	Assets	Active
305000001752000	DEF PEAK DEMAND CGA	Assets	Active
304000001752200	DEF OFF-PEAK BAD DEBT RECONCIL	Assets	Active
305000001752200	DEF OFF-PEAK BAD DEBT RECONCIL	Assets	Active
304000001753000	ACCRUED REVENUE - LDAC ITMC - NH	Assets	Active
304000001754000	ACCRUED REVENUE - LDAC CCE - NH	Assets	Active
304000001755000	ACCRUED REVENUE - CC - NH	Assets	Active
304000001755001	ACCRUED REVENUE - CC - RES - NH	Assets	Active
304000001755002	ACCRUED REVENUE - CC - C&I - NH	Assets	Active
304000001756000	ACCRUED REVENUE - LDAC ERC - NH	Assets	Active
304000001757000	ACCRUED REVENUE - RCE - NH	Assets	Active

Account Code	Description	Type	Status
304000001758000	ACCRUED REVENUE - RPC - NH	Assets	Active
304000001759000	ACCRUED REVENUE - LIEAP - NH	Assets	Active
304000001760000	MISC DEFERRED GAS COSTS - NH	Assets	Active
305000001760000	MISC DEFERRED GAS COSTS - ME	Assets	Active
304000001760100	DEF ERC COSTS - NH	Assets	Active
305000001760100	DEF ERC COSTS - ME	Assets	Active
300000001810200	UNAMORTIZED DEBT EXPENSE	Assets	Active
304000001820000	REGULATORY ASSET -NH	Assets	Active
305000001820000	REGULATORY ASSET - ME	Assets	Active
304000001820027	REGULATORY ASSET - NON-DIST BAD DEBT - NH	Assets	Active
305000001820027	REGULATORY ASSET - NON-DIST BAD DEBT- ME	Assets	Active
304000001820300	REGULATORY ASSET - SFAS 109 - NH	Assets	Active
305000001820300	REGULATORY ASSET - SFAS 109 - ME	Assets	Active
300000001820306	REGULATORY ASSET - DEF ENVIRON COSTS (RATEPAYER)	Assets	Active
304000001820328	REGULATORY ASSET - RATE CASE - NH	Assets	Active
305000001820328	REGULATORY ASSET - RATE CASE - ME	Assets	Active
300000001820329	REGULATORY ASSET - RATE CASE - COMMON	Assets	Active
305000001820330	REG ASSET - RATE CASE - ME- CAST IRON DOCKET	Assets	Active
304000001820403	REGULATORY ASSET - PBOP - NH	Assets	Active
305000001820403	REGULATORY ASSET - PBOP - ME	Assets	Active
304000001820405	REGULATORY ASSET - PENSION - NH	Assets	Active
305000001820405	REGULATORY ASSET - PENSION - ME	Assets	Active
304000001820409	REGULATORY ASSET - PBOP FAS 158	Assets	Active
305000001820409	REGULATORY ASSET - PBOP FAS 158	Assets	Active
304000001820410	REGULATORY ASSET - PENSION FAS 158	Assets	Active
305000001820410	REGULATORY ASSET - PENSION FAS 158	Assets	Active
304000001820411	REGULATORY ASSET -SERP	Assets	Active
305000001820411	REGULATORY ASSET -SERP	Assets	Active
304000001820900	REG ASSET - PRODUCTION & STORAGE - NH	Assets	Active
305000001820900	REG ASSET - PRODUCTION & STORAGE - ME	Assets	Active
304000001821100	REG ASSET - WORK CAP - PEAK COMM - NH	Assets	Active
305000001821100	REG ASSET - WORK CAP - PEAK COMM - ME	Assets	Active
305000001821300	REG ASSET - WORK CAP - PEAK DEMAND - ME	Assets	Active
304000001821600	REG ASSET - DEF BAD DEBT - NH	Assets	Active
305000001821600	REG ASSET - DEF BAD DEBT - ME	Assets	Active
305000001821800	REG ASSET - OFF PEAK PROD & STOR DEMAND - ME	Assets	Active
304000001821900	REG ASSET - BAD DEBT GAS HOLDING - NH	Assets	Active
305000001821900	REG ASSET - BAD DEBT GAS HOLDING - ME	Assets	Active
305000001822000	REG ASSET - WORK CAP - OFF PEAK DEMAND - ME	Assets	Active
304000001822100	REG ASSET - WORK CAP - OFF PEAK COMM - NH	Assets	Active
305000001822100	REG ASSET - WORK CAP - OFF PEAK COMM - ME	Assets	Active
304000001822200	REG ASSET - OFF PEAK BAD DEBT - NH	Assets	Active
305000001822200	REG ASSET - OFF PEAK BAD DEBT - ME	Assets	Active
304000001822300	REG ASSET - PEAK - MISC OVERHEAD DEF - NH	Assets	Active
304000001822400	REG ASSET - OFF PEAK - MISC OVERHEAD DEF - NH	Assets	Active
304000001822500	REG ASSET - ERC COSTS - NH	Assets	Active
305000001822500	REG ASSET - ERC COSTS NEW - ME	Assets	Active
304000001822600	REG ASSET - PRODUCTION & STORAGE DEF - NH	Assets	Active
305000001822600	REG ASSET - PRODUCTION & STORAGE DEF - ME	Assets	Active
304000001822800	REG ASSET - PRICE RISK - C - NH	Assets	Active
305000001822800	REG ASSET - PRICE RISK - C - ME	Assets	Active
304000001822900	REG ASSET - ERC COSTS - NH	Assets	Active
305000001822900	REG ASSET - ERC COSTS - ME	Assets	Active
304000001823000	REG ASSET - FAS109 COSTS - NH	Assets	Active
305000001823000	REG ASSET - FAS109 COSTS - ME	Assets	Active
304000001823600	REG ASSET - ERC - PRIOR YEAR LAYERS - NH	Assets	Active
305000001823600	REG ASSET - ERC - PRIOR YEAR LAYERS - ME	Assets	Active
304000001824100	REG ASSET - DEF DSM IMPLEMENTATION - NH	Assets	Active
305000001824100	REG ASSET - DEF DSM IMPLEMENTATION - ME	Assets	Active
304000001824101	REG ASSET - DEF DSM IMPLEMENT - LI - NH	Assets	Active
305000001824101	REG ASSET - DEF DSM IMPLEMENT - LI - ME	Assets	Active
304000001824102	REG ASSET - DEF DSM IMPLEMENT - R - NH	Assets	Active
305000001824102	REG ASSET - DEF DSM IMPLEMENT - R - ME	Assets	Active
304000001824106	REG ASSET - DEF DSM IMPLEMENT - CI - NH	Assets	Active

Account Code	Description	Type	Status
305000001824106	REG ASSET - DEF DSM IMPLEMENT - CI - ME	Assets	Active
304000001824200	REG ASSET - ERC COSTS - NH	Assets	Active
305000001824200	REG ASSET - ERC COSTS - ME	Assets	Active
305000001824300	REG ASSET - DEBT REDEMPTION PREM - NC - ME	Assets	Active
304000001824400	REG ASSET - PRICE RISK - NC - NH	Assets	Active
305000001824400	REG ASSET - PRICE RISK - NC - ME	Assets	Active
304000001824900	REG ASSET - DEBT REDEMPTION PREM - NH	Assets	Active
304000001825000	REGULATORY ASSET - SFAS109 - NH	Assets	Active
305000001825000	REGULATORY ASSET - SFAS109 - ME	Assets	Active
304000001825200	REG ASSET - SFAS158 - PBOP - NH	Assets	Active
305000001825200	REG ASSET - SFAS158 - PBOP - ME	Assets	Active
305000001825900	ERC SITE COSTS - ME	Assets	Active
304000001826000	REG ASSET - CREDIT BAL ASSET TRANSFER TO LIAB - NH	Assets	Active
305000001826000	REG ASSET - CREDIT BAL ASSET TRANSFER TO LIAB - ME	Assets	Active
304000001826300	REG ASSET - SUPPLIER REFUND - COMM & DEM - NH	Assets	Active
305000001826300	REG ASSET - SUPPLIER REFUND - COMM & DEM - ME	Assets	Active
305000001826400	REG ASSET - SUPPLIER REFUND - DEM - ME	Assets	Active
304000001827000	REG ASSET - ERC - SITE COSTS - NH	Assets	Active
305000001827000	REG ASSET - ERC - SITE COSTS - ME	Assets	Active
305000001827100	REG ASSET - MANAGEMENT AUDIT - ME	Assets	Active
305000001827600	NU ME REG ASSET ME LOW INCOME	Assets	Active
304000001828000	REG ASSET - ARO ACCUMULATIVE EFFECT	Assets	Active
305000001828000	REG ASSET - ARO ACCUMULATIVE EFFECT	Assets	Active
304000001828100	REG ASSET - PNGTS RATE CASE - NH	Assets	Active
305000001828100	REG ASSET - PNGTS RATE CASE - ME	Assets	Active
304000001828110	REG ASSET - PNGTS 2010 RATE CASE - NH	Assets	Active
305000001828110	REG ASSET - PNGTS 2010 RATE CASE - ME	Assets	Active
304000001828200	REG ASSET - GRANITE RATE CASE- NH	Assets	Active
304000001828600	REV DEP/AMORT REG ASSET	Assets	Active
305000001828600	REV DEP/AMORT REG ASSET	Assets	Active
304000001829600	REG ASSET - SFAS158 - PENSION - NH	Assets	Active
305000001829600	REG ASSET - SFAS158 - PENSION - ME	Assets	Active
304000001829900	REG ASSET - RLIAP - NH	Assets	Active
304000001830000	PREL SURVEY & INVESTIGATION-NH	Assets	Active
305000001830000	PREL SURVEY & INVESTIGATION-ME	Assets	Active
300000001840000	ENG & OPER OVERHEADS	Assets	Active
304000001840000	ENG & OPER OVERHEADS - NH	Assets	Active
305000001840000	ENG & OPER OVERHEADS - ME	Assets	Active
304000001840002	GENERAL OVERHEADS - NH	Assets	Active
305000001840002	GENERAL OVERHEADS - ME	Assets	Active
304000001840099	NU CONVENIENCE BILLINGS - NH	Assets	Active
305000001840099	NU CONVENIENCE BILLINGS - ME	Assets	Active
304000001840100	TRANS EXP AUTOS - NH	Assets	Active
305000001840100	TRANS EXP AUTOS - ME	Assets	Active
304000001840200	TRANS EXP LIGHT VEHICLES - NH	Assets	Active
305000001840200	TRANS EXP LIGHT VEHICLES - ME	Assets	Active
304000001840300	HEAVY TRUCKS - NH	Assets	Active
305000001840300	HEAVY TRUCKS - ME	Assets	Active
304000001840400	GAS EXEMPT STOCK - NH	Assets	Active
305000001840400	GAS EXEMPT STOCK - ME	Assets	Active
304000001840600	SMALL TOOLS - NH	Assets	Active
305000001840600	SMALL TOOLS - ME	Assets	Active
304002501840700	WATER HEATER OVERHEADS - NH	Assets	Active
305002501840700	WATER HEATER OVERHEADS - ME	Assets	Active
304000001840800	CASH DISCOUNTS TAKEN - NH	Assets	Active
305000001840800	CASH DISCOUNTS TAKEN - ME	Assets	Active
304000001850000	TEMPORARY SERVICES - NH	Assets	Active
305000001850000	TEMPORARY SERVICES - ME	Assets	Active
304000001850099	NONPROD - CONTRA CLEARING ACCOUNT - NH	Assets	Active
305000001850099	NONPROD - CONTRA CLEARING ACCOUNT - ME	Assets	Active
304000001850100	NONPROD - GAS OPERATIONS - NH	Assets	Active
305000001850100	NONPROD - GAS OPERATIONS - ME	Assets	Active
304000001850200	NONPROD - GAS DISTRIBUTION - NH	Assets	Active
305000001850200	NONPROD - GAS DISTRIBUTION - ME	Assets	Active

Account Code	Description	Type	Status
304000001850300	NONPROD - CUSTOMER SERVICE - NH	Assets	Active
305000001850300	NONPROD - CUSTOMER SERVICE - ME	Assets	Active
300000001850500	NONPROD - METER WORK	Assets	Active
304000001860000	MISC DEFERRED DEBITS - NH	Assets	Active
305000001860000	MISC DEFERRED DEBITS - ME	Assets	Active
304000001860100	CAPITALIZED FRINGE BENEFITS - NH	Assets	Active
305000001860100	CAPITALIZED FRINGE BENEFITS - ME	Assets	Active
304000001860200	CAPITALIZED FRINGE BENEFITS - CONTRA ACCOUNT - NH	Assets	Active
305000001860200	CAPITALIZED FRINGE BENEFITS - CONTRA ACCOUNT - ME	Assets	Active
304000001860405	INTANGIBLE ASSET - PENSION ABO - NH	Assets	Active
305000001860405	INTANGIBLE ASSET - PENSION ABO - ME	Assets	Active
304000001860900	UNAPPLIED CUSTOMER PAYMENTS - NH	Assets	Active
305000001860900	UNAPPLIED CUSTOMER PAYMENTS - ME	Assets	Active
304000001861400	DEF ENVIRON COSTS (COMPANY) - NH	Assets	Active
305000001861400	DEF ENVIRON COSTS (COMPANY) - ME	Assets	Active
304000001863000	TRANSITION COSTS - NH	Assets	Active
305000001863000	TRANSITION COSTS - ME	Assets	Active
304000001863001	TRANSACTIONS COSTS - NH	Assets	Active
305000001863001	TRANSACTIONS COSTS - ME	Assets	Active
304000001863090	ACCUM AMORT - TRANSITION COSTS - NH	Assets	Active
305000001863090	ACCUM AMORT - TRANSITION COSTS - ME	Assets	Active
304000001863091	ACCUM AMORT-TRANSACTIONS COSTS - NH	Assets	Active
305000001863091	ACCUM AMORT-TRANSACTIONS COSTS - ME	Assets	Active
304000001864000	RATE CASE - NH	Assets	Active
305000001864000	RATE CASE - ME	Assets	Active
304000001865000	PLANT AND M&S ACCRUALS - NH	Assets	Active
305000001865000	PLANT AND M&S ACCRUALS - ME	Assets	Active
304000001868000	GAS SUPPLIER REFUND A/R - NH	Assets	Active
305000001868000	GAS SUPPLIER REFUND A/R	Assets	Active
300000001869100	DEF DEBIT - WIND STORM RESTORATION-UES	Assets	Active
304000001880000	RESEARCH AND DEVELOPMENT - NH	Assets	Active
305000001880000	RESEARCH AND DEVELOPMENT - ME	Assets	Active
304000001880100	ACCRUED DSM	Assets	Active
305000001880100	ACCRUED DSM	Assets	Active
304000001880200	ACCUM DEF SIT NONCURRENT-RL	Assets	Active
305000001880200	ACCUM DEF SIT NONCURRENT-RL	Assets	Active
304000001880201	ACCUM DEF FIT NONCURRENT-RL	Assets	Active
305000001880201	ACCUM DEF FIT NONCURRENT-RL	Assets	Active
304000001880300	ACCUM DEFERRED SIT-BONUS DEPR	Assets	Active
305000001880300	ACCUM DEFERRED SIT-BONUS DEPR	Assets	Active
304000001880400	DSM GENERAL ADMINISTRATIVE	Assets	Active
305000001880400	DSM GENERAL ADMINISTRATIVE	Assets	Active
304000001880500	RESIDENTIAL CUSTOM MEASURES	Assets	Active
305000001880500	RESIDENTIAL CUSTOM MEASURES	Assets	Active
304000001880600	RES. CON. SVCS. ENERGY ASSESS	Assets	Active
305000001880600	RES. CON. SVCS. ENERGY ASSESS	Assets	Active
304000001880700	LOW INCOME MEASUERS	Assets	Active
305000001880700	LOW INCOME MEASUERS	Assets	Active
304000001880800	MULTI FAMILY CUSTOM MEASURES	Assets	Active
305000001880800	MULTI FAMILY CUSTOM MEASURES	Assets	Active
304000001880900	SMALL C&I CUSTOM MEASURES	Assets	Active
305000001880900	SMALL C&I CUSTOM MEASURES	Assets	Active
304000001881000	MED & LARGE C&I CUSTOM MEASURE	Assets	Active
305000001881000	MED & LARGE C&I CUSTOM MEASURE	Assets	Active
304000001881100	GASNTWRKS RES HIGH EFF HEAT	Assets	Active
305000001881100	GASNTWRKS RES HIGH EFF HEAT	Assets	Active
304000001881200	GASNTWRK RES & SM C&I H2O HEAT	Assets	Active
305000001881200	GASNTWRK RES & SM C&I H2O HEAT	Assets	Active
304000001881300	GASNTWRK COMM HIGH EFF HEAT	Assets	Active
305000001881300	GASNTWRK COMM HIGH EFF HEAT	Assets	Active
304000001881400	GASNTWRK INFRARED HEATERS	Assets	Active
305000001881400	GASNTWRK INFRARED HEATERS	Assets	Active
304000001881500	DSM GENERAL EXPENSES	Assets	Active
305000001881500	DSM GENERAL EXPENSES	Assets	Active

Account Code	Description	Type	Status
304000001881600	ENERGY STAR WINDOWS	Assets	Active
305000001881600	ENERGY STAR WINDOWS	Assets	Active
304000001881700	ENERGY STAR RESIDENT THERMOSTAT	Assets	Active
305000001881700	ENERGY STAR RESIDENT THERMOSTAT	Assets	Active
304000001881800	ENERGY STAR C&I THERMOSTAT	Assets	Active
305000001881800	ENERGY STAR C&I THERMOSTAT	Assets	Active
304000001881900	FOOD SERVICE EQUIPMENT	Assets	Active
305000001881900	FOOD SERVICE EQUIPMENT	Assets	Active
304000001882000	DSM GASNETWORKS MISC EXPENSE	Assets	Active
305000001882000	DSM GASNETWORKS MISC EXPENSE	Assets	Active
304000001882100	MISC EXTERNAL	Assets	Active
305000001882100	MISC EXTERNAL	Assets	Active
304000001882200	WEATHERIZATION REBATE INTERNAL	Assets	Active
305000001882200	WEATHERIZATION REBATE INTERNAL	Assets	Active
304000001882300	DSM CLEARED	Assets	Active
305000001882300	DSM CLEARED	Assets	Active
304000001886000	RESIDENTIAL CUSTOM MEASURES	Assets	Active
305000001886000	RESIDENTIAL CUSTOM MEASURES	Assets	Active
304000001886100	RES. CON. SVCS. ENERGY ASSESS	Assets	Active
305000001886100	RES. CON. SVCS. ENERGY ASSESS	Assets	Active
304000001886200	LOW INCOME MEASURES	Assets	Active
305000001886200	LOW INCOME MEASURES	Assets	Active
304000001886300	MULTI FAMILY CUSTOM MEASURES	Assets	Active
305000001886300	MULTI FAMILY CUSTOM MEASURES	Assets	Active
304000001886400	SMALL C&I CUSTOM MEASURES	Assets	Active
305000001886400	SMALL C&I CUSTOM MEASURES	Assets	Active
304000001886500	MED & LARGE C&I CUSTOM MEASURE	Assets	Active
305000001886500	MED & LARGE C&I CUSTOM MEASURE	Assets	Active
304000001886600	GASNTWRKS RES HIGH EFF HEAT	Assets	Active
305000001886600	GASNTWRKS RES HIGH EFF HEAT	Assets	Active
304000001886700	GASNTWRK RES & SM C&I H2O HEAT	Assets	Active
305000001886700	GASNTWRK RES & SM C&I H2O HEAT	Assets	Active
304000001886800	GASNTWRK COMM HIGH EFF HEAT	Assets	Active
305000001886800	GASNTWRK COMM HIGH EFF HEAT	Assets	Active
304000001886900	GASNTWRK COMM HIGH EFF HEAT	Assets	Active
305000001886900	GASNTWRK COMM HIGH EFF HEAT	Assets	Active
304000001890000	POWER PLANT INTERCO TRANSFERS - NH	Assets	Active
305000001890000	POWER PLANT INTERCO TRANSFERS - ME	Assets	Active
304000001890100	WORKORDER MANAGEMENT PROJECT - NH	Assets	Active
305000001890100	WORKORDER MANAGEMENT PROJECT - ME	Assets	Active
304000001900000	REG OPEB MED SUBS DEF TAX FED - NH	Assets	Active
305000001900000	REG OPEB MED SUBS DEF TAX FED - ME	Assets	Active
304000001900100	ACCUM DEF FIT MISC - NH	Assets	Active
305000001900100	ACCUM DEF FIT MISC - ME	Assets	Active
300000001900101	ACCUM DEF FIT-CIAC	Assets	Active
304000001900130	DEF FIT-CIAC - NH	Assets	Active
305000001900130	DEF FIT-CIAC - ME	Assets	Active
304000001900200	ACCUM DEF SIT MISC - NH	Assets	Active
305000001900200	ACCUM DEF SIT MISC - ME	Assets	Active
300000001900201	ACCUM DEF SIT-CIAC	Assets	Active
304000001900230	DEF SIT - CIAC - NH	Assets	Active
305000001900230	DEF SIT - CIAC - ME	Assets	Active
304000001900300	REG ASSET - FAS109 TAXES	Assets	Active
305000001900300	REG ASSET - FAS109 TAXES	Assets	Active
304000001910000	MISC UNRECOVERED GAS COSTS - NH	Assets	Active
305000001910000	MISC UNRECOVERED GAS COSTS - ME	Assets	Active
304000001910900	UNRECOVERED GAS COSTS - OFF PEAK COMM - NH	Assets	Active
305000001910900	UNRECOVERED GAS COSTS - OFF PEAK COMM - ME	Assets	Active
304000001911000	UNRECOVERED GAS COSTS - OFF PEAK COMM - NH	Assets	Active
305000001911000	UNRECOVERED GAS COSTS - OFF PEAK DEMAND - ME	Assets	Active
304000001911900	UNRECOVERED GAS COSTS - PEAK COMM - NH	Assets	Active
305000001911900	UNRECOVERED GAS COSTS - PEAK COMM - ME	Assets	Active
304000001912000	UNRECOVERED GAS COSTS - PEAK COMM - NH	Assets	Active
305000001912000	UNRECOVERED GAS COSTS - PEAK DEMAND - ME	Assets	Active

Account Code	Description	Type	Status
304000001912900	DEFERRED UNBILLED - NH	Assets	Active
305000001912900	DEFERRED UNBILLED - ME	Assets	Active
304000001914000	DEFERRED HEDGING COSTS - NH	Assets	Active
305000001914000	DEFERRED HEDGING COSTS - ME	Assets	Active
304000001940200	NU SALE TO UTL - TRANSFORMATION COSTS	Assets	Active
305000001940200	NU SALE TO UTL - TRANSFORMATION COSTS	Assets	Active
304000001990000	ERROR SUSPENSE - NH	Assets	Active
305000001990000	ERROR SUSPENSE - NH	Assets	Active
300000002010000	CAPITAL STOCK COMMON	Equity	Active
304000002070000	PREM CAP STK COMMON	Equity	Active
305000002070000	PREM CAP STK COMMON	Equity	Active
300000002110000	MISC PAID IN CAPITAL	Equity	Active
300000002140000	CAP STK EXP - COMMON	Equity	Active
300000002160000	RETAINED EARNINGS	Equity	Active
304000002160000	RETAINED EARNINGS	Equity	Active
305000002160000	RETAINED EARNINGS	Equity	Active
300000002190000	OTHER COMPREHENSIVE INCOME	Equity	Active
300000002240000	REG NOTES HISTORY	Liability	Active
300000002240100	SENIOR NOTES 6.95%	Liability	Active
304000002240100	CURRENT MATURITIES OF LTD	Liability	Active
300000002240200	LT DEBT DUE WITHIN 1 YR	Liability	Active
304000002240200	MTN - 4.8% DUE 06-02-2013	Liability	Active
300000002240300	SENIOR NOTES 7.72%	Liability	Active
300000002240400	SENIOR NOTES PAY 5.29% DUE 030220	Liability	Active
300000002270000	CAPITAL LEASE OBLIG - NON CURRENT	Liability	Active
300000002290000	RESERVED RATE CASE REVENUE	Liability	Active
304000002308001	ACCUMULATIVE LIABILITY-ARO ASSET	Liability	Active
305000002308001	ACCUMULATIVE LIABILITY-ARO ASSET	Liability	Active
304000002308002	ACCUMULATIVE ACCRETION LIAB-ARO ASSET	Liability	Active
305000002308002	ACCUMULATIVE ACCRETION LIAB-ARO ASSET	Liability	Active
304000002308003	ACCUM LIAB-ARO ASSET-SETTLMNT REDUCTION	Liability	Active
305000002308003	ACCUM LIAB-ARO ASSET-SETTLMNT REDUCTION	Liability	Active
300000002310000	NOTES PAYABLE	Liability	Active
300000002320000	ACCOUNTS PAYABLE - OTHER	Liability	Active
300000002320100	ACCOUNTS PAYABLE	Liability	Active
300000002320101	ACCOUNTS PAYABLE - ACCRUAL	Liability	Active
300000002320110	ACCOUNTS PAYABLE - BB ADJ	Liability	Active
300000002320115	ACCOUNTS PAYABLE - NISOURCE	Liability	Active
300000002320120	ACCOUNTS PAYABLE - TO/FROM BAY STATE GAS	Liability	Active
300000002320140	A/P-CUR PORT PURCH POWER CONTRACTS	Liability	Active
300000002320200	PAYROLL PAYABLE	Liability	Active
300000002320201	ACCRUED PAYROLL	Liability	Active
300000002320240	A/P-CUR PORTION W10 LIABILITY	Liability	Active
300000002320307	A/P 401-K LOAN PYMTS	Liability	Active
300000002320320	BCBS CLAIMS SETTLEMENT	Liability	Active
300000002320321	HSA CONTRIBUTIONS	Liability	Active
300000002320322	LTD CONTRIBUTIONS	Liability	Active
300000002320400	A/P UNCLAIMED CHECKS	Liability	Active
300000002320500	A/P GAS PURCHASED	Liability	Active
300000002320800	P/R DEDUCTION - UNION DUES	Liability	Active
300000002321400	401 K RETIREMENT	Liability	Active
300000002321499	P/R DED-CO.SAVINGS PLAN	Liability	Active
300000002321500	ACCTS PAYABLE OTHER	Liability	Active
300000002321800	EMP STK PURCHASE PLAN	Liability	Active
300000002321900	CHARITY FUND	Liability	Active
300000002322000	ACCTS PAY WAGE ASSIGNMENT	Liability	Active
300000002322100	A/P CUSTOMER REFUNDS	Liability	Active
304000002322100	CUSTOMER REFUNDS - NH	Liability	Active
305000002322100	CUSTOMER REFUNDS - ME	Liability	Active
304000002322101	A/P - CUSTOMER DEPOSIT REFUND	Liability	Active
305000002322101	A/P - CUSTOMER DEPOSIT REFUND	Liability	Active
304000002322199	P/R DED-POLITICAL ACTIVITY	Liability	Active
305000002322199	P/R DED-POLITICAL ACTIVITY	Liability	Active
300000002322200	ENERGY EFFICIENCY FUNDS PAYABLE - ME	Liability	Active

Account Code	Description	Type	Status
300000002322299	MARKETING INCENTIVE COMP.	Liability	Active
300000002323000	DEPENDENT CARE DEDUC & REIMB	Liability	Active
300000002323099	P/R DED-SPFLD UNITED WAY	Liability	Active
300000002323199	P/R DED-BROCK UNIT/WAY	Liability	Active
300000002323200	OPTIONAL LIFE INS DEDUCTION	Liability	Active
300000002323300	OPTIONAL AD&D DEDUCTION	Liability	Active
300000002323500	HOME/AUTO INS DEDUCTION	Liability	Active
300000002323600	A/P MEDICAL REIMBURSEMENT	Liability	Active
300000002324299	NRS INCENTIVE	Liability	Active
300000002324399	ACCRUED A/P CAPITAL	Liability	Active
300000002326399	A/P OUTSTANDING CHECKS	Liability	Active
300000002326999	MONTHLY GAS COST ACCRUALS	Liability	Active
300000002327099	P/R DED-UNION DUES #1	Liability	Active
300000002328700	ACCTS PAY EMPL BONDS	Liability	Active
300000002328999	ACCRUED EMPLOYMENT AGREEMENTS	Liability	Active
300000002329299	P/R DED PAY-INVESTMNT PLAN	Liability	Active
300000002329399	P/R DED-DEPENDENT CARE	Liability	Active
300000002329499	P/R DED-CHILD SUP-WELF	Liability	Active
300000002329599	P/R DED GROUP TERM INS	Liability	Active
300000002329699	P/R DED HEALTH CARE SPENDING	Liability	Active
300000002329799	P/R DED ADD OPTION	Liability	Active
300000002329999	P/R DED MISC	Liability	Active
300000002330000	NOTE PAYABLE - CASHPOOL	Liability	Active
300000002340000	A/P ASSOC CO-VOUCHERS	Liability	Active
300000002340102	A/P ASSOC CO-FLEXI ONLY USC	Liability	Active
300000002340105	A/P ASSOC COS - SERVICE BILL	Liability	Active
300000002340110	A/P ASSOC COS - UES	Liability	Active
300000002340112	A/P ASSOC COS - USC	Liability	Active
300000002340113	A/P ASSOC COS - UPC	Liability	Active
300000002340114	A/P ASSOC COS - URC	Liability	Active
300000002340115	A/P ASSOC COS - UC	Liability	Active
300000002340120	A/P ASSOC COS - FGE	Liability	Active
300000002340121	A/P ASSOC COS - FEDCO	Liability	Active
300000002340124	A/P ASSOC COS - URI	Liability	Active
300000002340125	A/P ASSOC COS - UI	Liability	Active
300000002340126	A/P ASSOC COS - USOURCE	Liability	Active
300000002340133	A/P ASSOC COS - GSG	Liability	Active
300000002340199	A/P-ASSOC.CO-BSG-LT	Liability	Active
300000002340699	A/P NISOURCE SHARED SERVICES	Liability	Active
300000002340899	A/P TO NISOURCE HOLDING CO.	Liability	Active
300000002341899	A/P-Serv.co Contract bill acrl	Liability	Active
300000002342299	A/P A7 NI Deferred Comp	Liability	Active
300000002342799	A/P A7 ESPP PLAN	Liability	Active
300000002343499	A/P TO COH	Liability	Active
304000002350100	CUSTOMER DEPOSITS ACTIVE - NH	Liability	Active
305000002350100	CUSTOMER DEPOSITS ACTIVE - ME	Liability	Active
304000002350300	CUSTOMER BILLED DEPOSITS - NH	Liability	Active
305000002350300	CUSTOMER BILLED DEPOSITS - ME	Liability	Active
300000002350900	ABANDONED PROPERTY	Liability	Active
304000002350901	A/P-UNCLAIMED CREDIT BALANCE REFUNDS	Liability	Active
305000002350901	A/P-UNCLAIMED CREDIT BALANCE REFUNDS	Liability	Active
300000002360000	TAXES ACCRUED - OTHER	Liability	Active
304000002360130	FED INC TAX CURRENT - NH	Liability	Active
305000002360130	FED INC TAX CURRENT - ME	Liability	Active
300000002360131	FED INC TAX PRIOR	Liability	Active
304000002360131	FED INC TAX PRIOR - NH	Liability	Active
305000002360131	FED INC TAX PRIOR - ME	Liability	Active
304000002360230	NH INC TAX - CURRENT	Liability	Active
304000002360231	NH INC TAX - PRIOR	Liability	Active
305000002360231	ME INC TAX - PRIOR	Liability	Active
305000002360232	MAINE INC TAX - CURRENT	Liability	Active
304000002360233	NH - INC TAX -PRIOR	Liability	Active
305000002360233	MAINE INC TAX - PRIOR	Liability	Active
304000002360240	STATE BET-CURRENT	Liability	Active

Account Code	Description	Type	Status
304000002360241	STATE BET-PRIOR	Liability	Active
300000002360244	NY INC TAX CURRENT	Liability	Active
300000002360245	NY INC TAX PRIOR	Liability	Active
300000002360310	TAXES FICA	Liability	Active
304000002360310	TAXES FICA-NU NH	Liability	Active
305000002360310	TAXES FICA-NU ME	Liability	Active
300000002360410	TAXES FEDERAL UNEMPLOYMNT	Liability	Active
304000002360410	TAXES FEDERAL UNEMPLOYMNT-NU NH	Liability	Active
305000002360410	TAXES FEDERAL UNEMPLOYMNT-NU ME	Liability	Active
304000002360611	TAXES UNEMPLOYMENT-NH	Liability	Active
305000002360611	TAXES UNEMPLOYMENT-ME	Liability	Active
305000002360811	TAXES STATE HEALTH-ME	Liability	Active
304000002367600	LOCAL OPERATING PROP - NH	Liability	Active
305000002367600	LOCAL OPERATING PROP - ME	Liability	Active
300000002370000	INTEREST ACCRUED	Liability	Active
300000002370099	INTEREST - MISC	Liability	Active
300000002370600	INTEREST FUNDED DEBT	Liability	Active
300000002370700	ACCRUED INTEREST - FUNDS POOL	Liability	Active
304000002370800	INT ACCR-CUSTOMER DEPOSITS	Liability	Active
305000002370800	INT ACCR-CUSTOMER DEPOSITS	Liability	Active
300000002380100	DIVIDENDS DECLARED-PREFERRED	Liability	Active
300000002380200	DIVIDENDS DECLARED-COMMON	Liability	Active
304000002380200	DIVIDENDS DECLARED-COMMON	Liability	Active
305000002380200	DIVIDENDS DECLARED-COMMON	Liability	Active
300000002410310	EMPL FICA WITHHOLDING TAX	Liability	Active
300000002410410	EMPL FED WITHHOLDING TAX	Liability	Active
300000002410611	EMPL STATE WITHHOLDING TAX - MA	Liability	Active
300000002410616	EMPL STATE WITHHOLDING TAX - ME	Liability	Active
305000002411900	SALES TAX PAYABLE - ME	Liability	Active
300000002411901	SALES TAX ABATEMENT	Liability	Active
305000002411901	SALES TAX ABATEMENT	Liability	Active
300000002420000	MISC ACCRUED LIABILITIES	Liability	Active
304000002420000	MISC ACCRUED LIABILITIES	Liability	Active
305000002420000	MISC ACCRUED LIABILITIES	Liability	Active
304000002420320	ACCRUED HEALTH INSURANCE	Liability	Active
305000002420320	ACCRUED HEALTH INSURANCE	Liability	Active
304000002420325	ACCRUED DENTAL INSURANCE	Liability	Active
305000002420325	ACCRUED DENTAL INSURANCE	Liability	Active
304000002420401	ACCRUED LEGAL-LOCAL-NH	Liability	Active
305000002420401	ACCRUED LEGAL-LOCAL-ME	Liability	Active
304000002420402	ACCRUED LEGAL-CORP-NH	Liability	Active
305000002420402	ACCRUED LEGAL-CORP-ME	Liability	Active
304000002420403	ACCRUED LEGAL-POWER SUPPLY-NH	Liability	Active
305000002420403	ACCRUED LEGAL-POWER SUPPLY-ME	Liability	Active
304000002420404	ACCRUED LEGAL-REGULATORY-NH	Liability	Active
305000002420404	ACCRUED LEGAL-REGULATORY-ME	Liability	Active
304000002420405	ACCRUED LEGAL-MISC-NH	Liability	Active
305000002420405	ACCRUED LEGAL-MISC-ME	Liability	Active
300000002420406	ACCRUED LEGAL-ACCOUNTING	Liability	Active
304000002420505	ACCRUE PUC ASSESSMENT- NH	Liability	Active
305000002420505	ACCRUE PUC ASSESSMENT- ME	Liability	Active
300000002420510	ACCRUED LEGAL MISC	Liability	Active
300000002420600	FAS 158 ADJ - SERP CURRENT	Liability	Active
304000002420600	FAS 158 ADJ-SERP CURRENT	Liability	Active
305000002420600	FAS 158 ADJ - SERP CURRENT	Liability	Active
300000002420699	ACCRUED SERP - HISTORY	Liability	Active
300000002420700	ACCRUED INSURANCE - OTHER	Liability	Active
300000002420800	ACCRUED AUDIT FEES	Liability	Active
300000002420900	ACCRUED SEVERANCE	Liability	Active
304000002421000	UNDISTRIB PURCHASE CAPACITY/DEMAND REFUNDS - NH	Liability	Active
305000002421000	UNDISTRIB PURCHASE CAPACITY/DEMAND REFUNDS - ME	Liability	Active
304000002421100	UNDISTRIB COMMODITY SUPPLIER REFUNDS - NH	Liability	Active
300000002421800	SFAS 106 LIABILITY	Liability	Active
304000002422500	GAS SUPPLIER REFUNDS	Liability	Active

Account Code	Description	Type	Status
305000002422500	GAS SUPPLIER REFUNDS	Liability	Active
300000002422600	INCENTIVE COMPENSATION	Liability	Active
304000002422600	ACCRUED INCENTIVE COMPENSATION	Liability	Active
305000002422600	ACCRUED INCENTIVE COMPENSATION	Liability	Active
304000002423000	ACCRUED VACATION-NH	Liability	Active
305000002423000	ACCRUED VACATION-ME	Liability	Active
304000002423110	INSURANCE CLAIMS RESERVE - NH	Liability	Active
305000002423110	INSURANCE CLAIMS RESERVE - ME	Liability	Active
300000002423200	A/P ACCRUAL	Liability	Active
300000002423400	ACCRUED POSTAGE	Liability	Active
300000002423500	CR BAL MARGIN DEPOSIT	Liability	Active
304000002423600	ACCRUED SFAS 112	Liability	Active
305000002423600	ACCRUED SFAS 112	Liability	Active
304000002423700	CURRENT ERC LIABILITIES	Liability	Active
305000002423700	CURRENT ERC LIABILITIES	Liability	Active
304000002423800	PROFIT SHARING LIABILITY	Liability	Active
305000002423800	PROFIT SHARING LIABILITY	Liability	Active
304000002423900	ACCRUED PROFESSIONAL SERVICES	Liability	Active
305000002423900	ACCRUED PROFESSIONAL SERVICES	Liability	Active
300000002424000	CREDIT BALANCE TRANSFER - 191	Liability	Active
300000002424100	SHORT TERM OPEB LIAB	Liability	Active
304000002424200	CREDIT BUDGET BALANCES LIAB - NH	Liability	Active
305000002424200	CREDIT BUDGET BALANCES LIAB - ME	Liability	Active
304000002424300	PRICE RISK LIABILITY SHORT TERM- NH	Liability	Active
305000002424300	PRICE RISK LIABILITY SHORT TERM- ME	Liability	Active
304000002424411	ATV RECONCILIATION ACCRUAL - NH-PEAK	Liability	Active
305000002424415	ATV RECONCILIATION ACCRUAL - ME- PEAK	Liability	Active
304000002424441	ATV RECONCILIATION ACCRUAL - NH-OFF PEAK	Liability	Active
305000002424445	ATV RECONCILIATION ACCRUAL - ME- OFF PEAK	Liability	Active
300000002424500	ACQUISITION SETTLEMENT ACCRUAL	Liability	Active
300000002424600	TRANSITION SERVICES ACCRUAL	Liability	Active
300000002430000	CAPITAL LEASE OBLIG - CURRENT	Liability	Active
304000002440000	PRICE RISK LIABILITY - NH	Liability	Active
305000002440000	PRICE RISK LIABILITY - ME	Liability	Active
304000002440100	PRICE RISK LIABILITY - NC - NH	Liability	Active
305000002440100	PRICE RISK LIABILITY - NC - ME	Liability	Active
304000002481000	ACCUM DEF SIT-CURRENT RA	Liability	Active
305000002481000	ACCUM DEF SIT-CURRENT RA	Liability	Active
304000002481100	ACCUM DEF FIT-CURRENT RA	Liability	Active
305000002481100	ACCUM DEF FIT-CURRENT RA	Liability	Active
304000002520100	LT REIMB CONTRIBUTIONS - NH	Liability	Active
305000002520100	LT REIMB CONTRIBUTIONS - ME	Liability	Active
304000002520200	CUST ADV CONST - NH	Liability	Active
305000002520200	CUST ADV CONST - ME	Liability	Active
304000002530200	CUSTOMER GIFT CERTIFICATE - NH	Liability	Active
305000002530200	CUSTOMER GIFT CERTIFICATE - ME	Liability	Active
304000002530301	LT ERC COSTS - NH	Liability	Active
305000002530301	LT ERC COSTS - ME	Liability	Active
304000002530401	FASB 87 - ACCRUED PENSION	Liability	Active
305000002530401	FASB 87 - ACCRUED PENSION	Liability	Active
304000002530403	ACCRUED SFAS 106 LIABILITY	Liability	Active
305000002530403	ACCRUED SFAS 106 LIABILITY	Liability	Active
304000002530411	FAS 158 ADJ - PENSION	Liability	Active
305000002530411	FAS 158 ADJ - PENSION	Liability	Active
304000002530413	FAS 158 ADJ - PBOP	Liability	Active
305000002530413	FAS 158 ADJ - PBOP	Liability	Active
304000002530414	FAS 158 ADJ - SERP	Liability	Active
305000002530414	FAS 158 ADJ - SERP	Liability	Active
304000002530900	OPEB LIABILITY - NH	Liability	Active
305000002530900	OPEB LIABILITY - ME	Liability	Active
300000002531000	OTHER MISC NONCURRENT LIABILITIES	Liability	Active
304000002531000	OTHER MISC NONCURRENT LIABILITIES	Liability	Active
305000002531000	OTHER MISC NONCURRENT LIABILITIES	Liability	Active
300000002531100	UNAMORTIZED I.T.C.	Liability	Active

Account Code	Description	Type	Status
300000002531200	NONCOMPETES	Liability	Active
304000002540000	REG LIAB - PRICE RISK - C - NH	Liability	Active
305000002540000	REG LIAB - PRICE RISK - C - ME	Liability	Active
304000002540100	REG LIAB - PRICE RISK - NC - NH	Liability	Active
305000002540100	REG LIAB - PRICE RISK - NC - ME	Liability	Active
304000002540500	REG LIAB - FAS109 COSTS - NH	Liability	Active
305000002540500	REG LIAB - FAS109 COSTS - ME	Liability	Active
304000002540900	REG LIAB - PBOP MEDICARE SUBS - NH	Liability	Active
305000002540900	REG LIAB - PBOP MEDICARE SUBS - ME	Liability	Active
300000002541000	REGULATORY LIABILITY - PLANT	Liability	Active
304000002541000	COST OF REMOVAL - NH	Liability	Active
305000002541000	COST OF REMOVAL - MA	Liability	Active
304000002541100	ACCM DEPRECIATION	Liability	Active
305000002541100	ACCM DEPRECIATION	Liability	Active
304000002541200	SALVAGE PRODUCT STRUCTURE	Liability	Active
305000002541200	SALVAGE PRODUCT STRUCTURE	Liability	Active
304000002544300	PRICK RISK LIABILITY - NC	Liability	Active
305000002544300	PRICK RISK LIABILITY - NC	Liability	Active
305000002545000	REG LIAB - SQI NOPV- ME	Liability	Active
305000002545100	REG LIAB - SQI PENALTY - METER TO CASH - ME	Liability	Active
305000002545200	MAINE NOPV ACCRUAL	Liability	Active
304000002545500	CREDIT BAL ASSETS TRANSFERRED TO LIAB - NH	Liability	Active
305000002545500	CREDIT BAL ASSETS TRANSFERRED TO LIAB - ME	Liability	Active
304000002547500	REV DEP/AMORT REG LIAB FAS 109	Liability	Active
305000002547500	REV DEP/AMORT REG LIAB FAS 109	Liability	Active
304000002548000	REG LIABILITY-COR IMBEDDED IN DEPR RESERVE (ACCUM)	Liability	Active
305000002548000	REG LIABILITY-COR IMBEDDED IN DEPR RESERVE (ACCUM)	Liability	Active
304000002550100	UNAMORTIZED ITC - NH	Liability	Active
305000002550100	UNAMORTIZED ITC - ME	Liability	Active
304000002551000	REV DEP/AMORT UNAMORT ITC	Liability	Active
305000002551000	REV DEP/AMORT UNAMORT ITC	Liability	Active
300000002570000	RES/AMORT-LNG LEASEHOLD IM	Liability	Active
304000002570000	RES/AMORT-LNG LEASEHOLD IMP - NH	Liability	Active
305000002570000	RES/AMORT-LNG LEASEHOLD IMP - ME	Liability	Active
304000002570099	RES AMORT - MISC	Liability	Active
305000002570099	RES AMORT - MISC	Liability	Active
300000002573200	RES AMORT-EXCESS COST-NH	Liability	Active
300000002575100	RES AMORT-Client Server	Liability	Active
300000002577000	RES AMORT-UNH BOILER PLANT	Liability	Active
300000002578700	DEPR FOR MISC SOFTWARE	Liability	Active
305000002601400	SALES TAX CHARGE OFF REDUCTION	Liability	Active
304000002630100	LT ERC LIABILITIES	Liability	Active
305000002630100	LT ERC LIABILITIES	Liability	Active
304000002630200	FAS 112 POSTRETIREMENT LIABILITY - NH	Liability	Active
305000002630200	FAS 112 POSTRETIREMENT LIABILITY - ME	Liability	Active
304000002630400	SERP - NH	Liability	Active
305000002630400	SERP - ME	Liability	Active
304000002630500	OPEB LIABILITY - NH	Liability	Active
305000002630500	OPEB LIABILITY - ME	Liability	Active
300000002640000	CUSTOMER REFUNDS	Liability	Active
300000002650000	INTERR PROF BUNDLED COST	Liability	Active
300000002660000	NON UTILITY LIABILITIES	Liability	Active
300000002664200	SALVAGE-NON UTILITY	Liability	Active
305000002665000	RES AMORT-PORT.GAS MERGE	Liability	Active
305000002665200	RES/DEPREC-NON UTIL-PROPA	Liability	Active
305000002665300	RES/AMORT - NON UTILITY	Liability	Active
305000002665400	RES/MAINE RENTAL PROGRAM	Liability	Active
305000002665500	RES DEPRC-RENTAL BUILDING	Liability	Active
305000002665600	ADMIRALTY VILLAGE MAINS/SERVIC	Liability	Active
304000002680100	RES DEFERRED FIT - PENSIONS	Liability	Active
305000002680100	RES DEFERRED FIT - PENSIONS	Liability	Active
304000002680200	RES DEFERRED SIT - PENSIONS	Liability	Active
305000002680200	RES DEFERRED SIT - PENSIONS	Liability	Active
304000002680300	RES DEFERRED FIT - PROPERTY	Liability	Active

Account Code	Description	Type	Status
305000002680300	RES DEFERRED FIT - PROPERTY	Liability	Active
304000002680400	RES DEF SIT-PROPERTY	Liability	Active
305000002680400	RES DEFERRED SIT - PROPERTY	Liability	Active
304000002680500	RES DEF FIT-OTHER CURRENT	Liability	Active
305000002680500	RES DEF FIT-OTHER CURRENT	Liability	Active
304000002680600	RES DEF FIT-OTHER LONG TERM	Liability	Active
305000002680600	RES DEF FIT-OTHER LONG TERM	Liability	Active
304000002680700	RES DEF SIT-OTHER LONG TERM	Liability	Active
305000002680700	RES DEF SIT-OTHER LONG TERM	Liability	Active
304000002680800	RES DEF SIT-OTHER CURRENT	Liability	Active
305000002680800	RES DEF SIT-OTHER CURRENT	Liability	Active
304000002780100	ACC DEF SIT-NONCURRENT	Liability	Active
305000002780100	ACC DEF SIT-NONCURRENT	Liability	Active
304000002780200	ACC DEF FIT-NONCURRENT	Liability	Active
305000002780200	ACC DEF FIT-NONCURRENT	Liability	Active
304000002780300	ACCUM DEF FIT MERGER PAA	Liability	Active
305000002780300	ACCUM DEF FIT MERGER PAA	Liability	Active
304000002780400	ACCUM DEF SIT-MERGER PAA	Liability	Active
305000002780400	ACCUM DEF SIT-MERGER PAA	Liability	Active
304000002780500	Def Taxes - Merger Comp - Fed	Liability	Active
305000002780500	Def Taxes - Merger Comp - Fed	Liability	Active
304000002780600	Def Taxes - Merger Comp -State	Liability	Active
305000002780600	Def Taxes - Merger Comp -State	Liability	Active
304000002780700	REG LIAB-FAS109 TAXES	Liability	Active
305000002780700	REG LIAB-FAS109 TAXES	Liability	Active
304000002822200	RES DEFERRED FIT-PROP 26848	Liability	Active
305000002822200	RES DEFERRED FIT-PROP 26848	Liability	Active
304000002824200	RES DEFERRED SIT-PROP 26849	Liability	Active
305000002824200	RES DEFERRED SIT-PROP 26849	Liability	Active
304000002827200	DEFERRED FED TAX - REV DEPR/AMO	Liability	Active
305000002827200	DEFERRED FED TAX - REV DEPR/AMO	Liability	Active
304000002828200	DEFERRED ST TAX - REV DEPR/AMO	Liability	Active
305000002828200	DEFERRED- REV DEPR/AMO	Liability	Active
304000002830021	ACCUM DEF FIT NONCURR-RL 18811	Liability	Active
305000002830021	ACCUM DEF FIT NONCURR-RL 18811	Liability	Active
304000002830022	RES DEF FIT-OTHER LT 26898	Liability	Active
305000002830022	RES DEF FIT-OTHER LT 26898	Liability	Active
304000002830023	ACC DEF FIT-NONCURRENT 27811	Liability	Active
305000002830023	ACC DEF FIT-NONCURRENT 27811	Liability	Active
304000002830024	ACCUM DEF FIT MERGER PAA 27812	Liability	Active
305000002830024	ACCUM DEF FIT MERGER PAA 27812	Liability	Active
304000002830025	DEF TAX - MERGER - FED 27818	Liability	Active
305000002830025	DEF TAX - MERGER - FED 27818	Liability	Active
304000002830027	RES DEF FIT-PENSIONS Non Curr	Liability	Active
305000002830027	RES DEF FIT-PENSIONS Non Curr	Liability	Active
304000002830028	FAS 158 Pension Federal	Liability	Active
305000002830028	FAS 158 Pension Federal	Liability	Active
304000002830029	FAS 158 OPEB Federal	Liability	Active
305000002830029	FAS 158 OPEB Federal	Liability	Active
304000002830031	RES DEF SIT-PENSIONS 26819	Liability	Active
305000002830031	RES DEF SIT-PENSIONS 26819	Liability	Active
304000002830033	RES DEF SIT OTHER CUR 26889	Liability	Active
305000002830033	RES DEF SIT OTHER CUR 26889	Liability	Active
304000002830035	DEFER TAXES STATE-DEF CAS COST	Liability	Active
305000002830035	DEFER TAXES STATE-DEF CAS COST	Liability	Active
304000002830041	ACCUM DEF SIT NONCURRENT-RL	Liability	Active
305000002830041	ACCUM DEF SIT NONCURRENT-RL	Liability	Active
304000002830042	RES DEF SIT-OTHER LT 26899	Liability	Active
305000002830042	RES DEF SIT-OTHER LT 26899	Liability	Active
304000002830043	ACC DEF SIT-NONCURRENT 27810	Liability	Active
305000002830043	ACC DEF SIT-NONCURRENT 27810	Liability	Active
304000002830044	ACCUM DEF SIT-MERGER PAA 27814	Liability	Active
305000002830044	ACCUM DEF SIT-MERGER PAA 27814	Liability	Active
304000002830045	DEF TAX MERGR COMP STATE 27819	Liability	Active

Account Code	Description	Type	Status
305000002830045	DEF TAX MERGR COMP STATE 27819	Liability	Active
304000002830046	ACCUM DEF SIT-BONUS 18819	Liability	Active
305000002830046	ACCUM DEF SIT-BONUS 18819	Liability	Active
304000002830047	RES DEF SIT - Pensions Non-Cur	Liability	Active
305000002830047	RES DEF SIT - Pensions Non-Cur	Liability	Active
304000002830048	FAS 158 Pension State	Liability	Active
305000002830048	FAS 158 Pension State	Liability	Active
304000002830049	FAS 158 OPEB State	Liability	Active
305000002830049	FAS 158 OPEB State	Liability	Active
304000002830131	DEF FIT - ACCEL DEPR - NH	Liability	Active
305000002830131	DEF FIT - ACCEL DEPR - ME	Liability	Active
304000002830132	DEF FIT - PRA - NH	Liability	Active
305000002830132	DEF FIT - PRA - ME	Liability	Active
304000002830133	DEF FIT - RETIREMENT LOSS - NH	Liability	Active
305000002830133	DEF FIT - RETIREMENT LOSS - ME	Liability	Active
304000002830134	DEF FIT - SFAS 106 OPEB - NH	Liability	Active
305000002830134	DEF FIT - SFAS 106 OPEB - ME	Liability	Active
304000002830135	DEF FIT - PENSION FAS 87 - NH	Liability	Active
305000002830135	DEF FIT - PENSION FAS 87 - ME	Liability	Active
304000002830138	DEF FIT - BAD DEBT - NH	Liability	Active
305000002830138	DEF FIT - BAD DEBT - ME	Liability	Active
304000002830139	DEF FIT - ACCRUED REVENUE - NH	Liability	Active
305000002830139	DEF FIT - ACCRUED REVENUE - ME	Liability	Active
304000002830140	DEF FIT - CATH PROTECT - NH	Liability	Active
305000002830140	DEF FIT - CATH PROTECT - ME	Liability	Active
304000002830141	DEF FIT - PREPAID PROPERTY TAX - NH	Liability	Active
305000002830141	DEF FIT - PREPAID PROPERTY TAX - ME	Liability	Active
304000002830142	DEF FIT - DEF RATE CASE COSTS - NH	Liability	Active
305000002830142	DEF FIT - DEF RATE CASE COSTS - ME	Liability	Active
304000002830143	DEF FIT - REMEDIATION - NH	Liability	Active
305000002830143	DEF FIT - REMEDIATION - ME	Liability	Active
304000002830145	DEF FIT - OVERHEADS - NH	Liability	Active
305000002830145	DEF FIT - OVERHEADS - ME	Liability	Active
304000002830147	DEF FIT - PENSION FAS 87 REG ASSET - NH	Liability	Active
305000002830147	DEF FIT - PENSION FAS 87 REG ASSET - ME	Liability	Active
304000002830149	DEF FIT - SFAS 106 OPEB REG ASSET - NH	Liability	Active
305000002830149	DEF FIT - SFAS 106 OPEB REG ASSET - ME	Liability	Active
304000002830150	DEF FIT - BAD DEBT-REG ASSET - NH	Liability	Active
305000002830150	DEF FIT - BAD DEBT-REG ASSET - ME	Liability	Active
304000002830151	DEF FIT - TRANSITION COSTS - NH	Liability	Active
305000002830151	DEF FIT - TRANSITION COSTS - ME	Liability	Active
304000002830152	DEF FIT - TRANSACTION COSTS - NH	Liability	Active
305000002830152	DEF FIT - TRANSACTION COSTS - ME	Liability	Active
304000002830153	DEF FIT - PURCHASE DISCOUNT - NH	Liability	Active
305000002830153	DEF FIT - PURCHASE DISCOUNT - ME	Liability	Active
304000002830154	DEF FIT-PURCHASED DISCOUNT - NH	Liability	Active
305000002830154	DEF FIT-PURCHASED DISCOUNT - ME	Liability	Active
304000002830155	DEF FIT - OTHER - NH	Liability	Active
305000002830155	DEF FIT - OTHER - ME	Liability	Active
300000002830159	DEF FIT FASB 158 ADJ - PBOP	Liability	Active
304000002830159	DEF FIT FASB 158 ADJ - PBOP	Liability	Active
305000002830159	DEF FIT FASB 158 ADJ - PBOP	Liability	Active
300000002830160	DEF FIT- PENSION FAS 158	Liability	Active
304000002830160	DEF FIT- PENSION FAS 158	Liability	Active
305000002830160	DEF FIT- PENSION FAS 158	Liability	Active
304000002830163	DEF FIT - SFAS 158 SERP	Liability	Active
305000002830163	DEF FIT - SFAS 158 SERP	Liability	Active
304000002830164	DEF FIT - INSURANCE CLAIM RESERVE - NH	Liability	Active
305000002830164	DEF FIT - INSURANCE CLAIM RESERVE- ME	Liability	Active
304000002830231	DEF SIT- ACCEL DEPR - NH	Liability	Active
305000002830231	DEF SIT- ACCEL DEPR - ME	Liability	Active
304000002830232	DEF SIT- PRA - NH	Liability	Active
305000002830232	DEF SIT- PRA - ME	Liability	Active
304000002830233	DEF SIT- RETIREMENT LOSS - NH	Liability	Active

Account Code	Description	Type	Status
305000002830233	DEF SIT- RETIREMENT LOSS - ME	Liability	Active
304000002830234	DEF SIT- SFAS 106 OPEB - NH	Liability	Active
305000002830234	DEF SIT- SFAS 106 OPEB - ME	Liability	Active
304000002830235	DEF SIT- PENSION FAS 87 - NH	Liability	Active
305000002830235	DEF SIT- PENSION FAS 87 - ME	Liability	Active
304000002830238	DEF SIT- BAD DEBT - NH	Liability	Active
305000002830238	DEF SIT- BAD DEBT - ME	Liability	Active
304000002830239	DEF SIT- ACCRUED REVENUE - NH	Liability	Active
305000002830239	DEF SIT- ACCRUED REVENUE - ME	Liability	Active
304000002830240	DEF SIT- CATH PROTECT - NH	Liability	Active
305000002830240	DEF SIT- CATH PROTECT - ME	Liability	Active
304000002830241	DEF SIT- PREPAID PROPERTY TAXES - NH	Liability	Active
305000002830241	DEF SIT- PREPAID PROPERTY TAXES - ME	Liability	Active
304000002830242	DEF SIT- DEF RATE CASE COSTS - NH	Liability	Active
305000002830242	DEF SIT- DEF RATE CASE COSTS - ME	Liability	Active
304000002830243	DEF SIT- REMEDIATION - NH	Liability	Active
305000002830243	DEF SIT- REMEDIATION - ME	Liability	Active
304000002830245	DEF SIT- OVERHEADS - NH	Liability	Active
305000002830245	DEF SIT- OVERHEADS - ME	Liability	Active
304000002830247	DEF SIT - PENSION FAS 87 REG ASSET - NH	Liability	Active
305000002830247	DEF SIT - PENSION FAS 87 REG ASSET - ME	Liability	Active
304000002830249	DEF SIT - SFAS 106 OPEB REG ASSET - NH	Liability	Active
305000002830249	DEF SIT - SFAS 106 OPEB REG ASSET - ME	Liability	Active
304000002830250	DEF SIT - BAD DEBT-REG ASSET - NH	Liability	Active
305000002830250	DEF SIT - BAD DEBT-REG ASSET - ME	Liability	Active
304000002830251	DEFSIT - TRANSITION COSTS - NH	Liability	Active
305000002830251	DEFSIT - TRANSITION COSTS - ME	Liability	Active
304000002830252	DEF SIT - TRANSACTION COSTS - NH	Liability	Active
305000002830252	DEF SIT - TRANSACTION COSTS - ME	Liability	Active
304000002830253	DEF SIT - PURCHASE DISCOUNT - NH	Liability	Active
305000002830253	DEF SIT - PURCHASE DISCOUNT - ME	Liability	Active
304000002830254	DEF SIT-PURCHASED DISCOUNT - NH	Liability	Active
305000002830254	DEF SIT-PURCHASED DISCOUNT - ME	Liability	Active
300000002830259	DEF SIT FASB 158 ADJ - PBOP	Liability	Active
304000002830259	DEF SIT FASB 158 ADJ - PBOP	Liability	Active
305000002830259	DEF SIT FASB 158 ADJ - PBOP	Liability	Active
300000002830260	DEF SIT- PENSION FAS 158	Liability	Active
304000002830260	DEF SIT- PENSION FAS 158	Liability	Active
305000002830260	DEF SIT- PENSION FAS 158	Liability	Active
304000002830263	DEF SIT - SFAS 158 SERP	Liability	Active
305000002830263	DEF SIT - SFAS 158 SERP	Liability	Active
304000002830264	DEF SIT - INSURANCE CLAIM RESERVE- NH	Liability	Active
305000002830264	DEF SIT - INSURANCE CLAIM RESERVE - ME	Liability	Active
304000002835100	REV DEP/AMORT NC RL FEDERAL	Liability	Active
305000002835100	REV DEP/AMORT NC RL FEDERAL	Liability	Active
304000002836100	REV DEP/AMORT NC RL STATE	Liability	Active
305000002836100	REV DEP/AMORT NC RL STATE	Liability	Active
304000002837300	REV DEP/AMORT AC DEF FIT NC	Liability	Active
305000002837300	REV DEP/AMORT AC DEF FIT NC	Liability	Active
304000002837400	PAA FED - REV DEPR/AMORT	Liability	Active
305000002837400	PAA FED - REV DEPR/AMORT	Liability	Active
304000002837800	ACC DEF SIT DISALLOWED BONUS	Liability	Active
305000002837800	ACC DEF SIT DISALLOWED BONUS	Liability	Active
304000002838300	REV DEP/AMORT AC DEF SIT NC	Liability	Active
305000002838300	REV DEP/AMORT AC DEF SIT NC	Liability	Active
304000002838400	PAA STATE - REV DEPR/AMORT	Liability	Active
305000002838400	PAA STATE - REV DEPR/AMORT	Liability	Active
304010004030000	DEPRECIATION GAS - NH	Expense	Active
305010004030000	DEPRECIATION GAS - ME	Expense	Active
304010004037000	GAAP - ADD BACK DEPR	Expense	Active
305010004037000	GAAP - ADD BACK DEPR	Expense	Active
304010004040300	AMORTIZATION OF COMP SOFTWARE	Expense	Active
305010004040300	AMORTIZATION OF COMP SOFTWARE	Expense	Active
305010004050200	AMORT-ORG.COSTS-BSG MERGE	Expense	Active

Account Code	Description	Type	Status
304010004052000	AMORTIZATION EXPENSE	Expense	Active
305010004052000	AMORTIZATION EXPENSE	Expense	Active
304010004052100	AMORT-UNH BOILER PLANT	Expense	Active
304010004053400	NIPSCO AMORTIZATION	Expense	Active
305010004053400	NIPSCO AMORTIZATION	Expense	Active
304010004053600	AMORT-FURNACE LEASE	Expense	Active
305010004053600	AMORT-FURNACE LEASE	Expense	Active
304010004057000	GAAP - ADD BACK AMORT	Expense	Active
305010004057000	GAAP - ADD BACK AMORT	Expense	Active
304010004060000	AMORT-INVESTMNT TAX CREDIT	Expense	Active
305010004060000	AMORT-INVESTMNT TAX CREDIT	Expense	Active
304010004060100	AMORTIZATION OF INTANGIBLE	Expense	Active
305010004060100	AMORTIZATION OF INTANGIBLE	Expense	Active
304010004067000	GAAP - ADD BACK PAA	Expense	Active
305010004067000	GAAP - ADD BACK PAA	Expense	Active
304010004067800	AMORT INV TAX CRED/ REV DEP AM	Expense	Active
305010004067800	AMORT INV TAX CRED/ REV DEP AM	Expense	Active
304010004070300	AMORT- REGULATORY ASSET - NH	Expense	Active
305010004070300	AMORT- REGULATORY ASSET - NH	Expense	Active
304010004070900	FAS 109 NET REG ASSET AMORT - NH	Expense	Active
305010004070900	FAS 109 NET REG ASSET AMORT - ME	Expense	Active
304010004070901	AMORT EXP-FAS 109 REG LIABILITY - GAS - NH	Expense	Active
305010004070901	AMORT EXP-FAS 109 REG LIABILITY - GAS - ME	Expense	Active
304010004073000	AMORT- TRANSITION COSTS - NH	Expense	Active
305010004073000	AMORT- TRANSITION COSTS - ME	Expense	Active
304010004073001	AMORT- TRANSACTION COSTS - NH	Expense	Active
305010004073001	AMORT- TRANSACTION COSTS - ME	Expense	Active
304010004077800	REG DR/CR FAS 109 REV DEPR AMO	Expense	Active
305010004077800	REG DR/CR FAS 109 REV DEPR AMO	Expense	Active
304910114078100	AMORT OF PNGTS RATE CASE COSTS	Expense	Active
300010004080000	OTHER TAXES	Expense	Active
304010004080000	OTHER TAXES	Expense	Active
305010004080000	OTHER TAXES	Expense	Active
300010004080001	OTHER TAXES CAPITALIZED	Expense	Active
304010004080001	OTHER TAXES CAPITALIZED	Expense	Active
305010004080001	OTHER TAXES CAPITALIZED	Expense	Active
300010004080005	OTHER TAXES - NON OPERATING	Expense	Active
304010004080005	OTHER TAXES - NON OPERATING	Expense	Active
305010004080005	OTHER TAXES - NON OPERATING	Expense	Active
304010004080111	NHBET TAX EXP- CURRENT	Expense	Active
300003004080310	TAXES FICA - COMMON	Expense	Active
304003004080310	TAXES FICA - NH	Expense	Active
305003004080310	TAXES FICA - ME	Expense	Active
300003004080410	TAXES FEDERAL UNEMPLOYMENT - COMMON	Expense	Active
304003004080410	TAXES FEDERAL UNEMPLOYMENT - NH	Expense	Active
305003004080410	TAXES FEDERAL UNEMPLOYMENT - ME	Expense	Active
300003004080611	TAXES UNEMPLOYMENT- COMMON	Expense	Active
304003004080611	TAXES UNEMPLOYMENT - NH	Expense	Active
305003004080611	TAXES UNEMPLOYMENT - ME	Expense	Active
300003004080810	TAXES STATE HEALTH - COMMON	Expense	Active
304003004080810	TAXES STATE HEALTH - NH	Expense	Active
305003004080810	TAXES STATE HEALTH - ME	Expense	Active
300010004081000	PAYROLL TAXES CAPTIALIZED - COMMON	Expense	Active
304010004081000	PAYROLL TAXES CAPTIALIZED - NH	Expense	Active
305010004081000	PAYROLL TAXES CAPTIALIZED - ME	Expense	Active
304010004081200	LOCAL OPER. PROPERTY TAX - NH	Expense	Active
305010004081200	LOCAL OPER. PROPERTY TAX - ME	Expense	Active
305010004081203	PROP TAX - NONOPERATING PROPERTY - ME	Expense	Active
300010004081300	PROPERTY TAX CAPITALIZED - COMMON	Expense	Active
304010004081300	PROPERTY TAX CAPITALIZED - NH	Expense	Active
305010004081300	PROPERTY TAX CAPITALIZED - ME	Expense	Active
304010004081400	MOTOR VEH EXCISE TAX EXP - NH	Expense	Active
305010004081400	MOTOR VEH EXCISE TAX EXP - ME	Expense	Active
304010004087300	CURRENT ST TAX - REV DEP/AMORT	Expense	Active

Account Code	Description	Type	Status
305010004087300	CURRENT ST TAX - REV DEP/AMORT	Expense	Active
304010004090130	FED INCOME TAX CURRENT - GAS - NH	Expense	Active
305010004090130	FED INCOME TAX CURRENT - GAS - ME	Expense	Active
304010004090131	FED INCOME TAX - PRIOR - GAS - NH	Expense	Active
305010004090131	FED INCOME TAX - PRIOR - GAS - ME	Expense	Active
304010004090132	FED INCOME TAX - NON OPER - GAS - NH	Expense	Active
305010004090132	FED INCOME TAX - NON OPER - GAS - ME	Expense	Active
304010004090230	STATE INCOME TAX EXP - CURRENT - NH	Expense	Active
305010004090230	STATE INCOME TAX EXP - CURRENT - ME	Expense	Active
304010004090231	STATE INCOME TAX EXP - PRIOR - NH	Expense	Active
305010004090231	STATE INCOME TAX EXP - PRIOR - ME	Expense	Active
300010004090232	STATE INC TAX-NON OPER-CURRENT-OTHER	Expense	Active
304010004090232	STATE INC TAX-NON OPER-CURRENT-NH	Expense	Active
305010004090232	STATE INC TAX-NON OPER-CURRENT-ME	Expense	Active
304010004097200	CURRENT FED TAX - REV DEP/AMOR	Expense	Active
305010004097200	CURRENT FED TAX - REV DEP/AMOR	Expense	Active
304010004100100	DEF FIT EXP - NH	Expense	Active
305010004100100	DEF FIT EXP - ME	Expense	Active
304010004100130	DEF FIT EXP-ACCEL DEPRECIATION - NH	Expense	Active
305010004100130	DEF FIT EXP-ACCEL DEPRECIATION - ME	Expense	Active
304010004100132	DEF FIT EXP-PRA - NH	Expense	Active
305010004100132	DEF FIT EXP-PRA - ME	Expense	Active
304010004100133	DEF FIT EXP-RETIREMENT LOSS - NH	Expense	Active
305010004100133	DEF FIT EXP-RETIREMENT LOSS -ME	Expense	Active
304010004100134	DEF FIT EXP-SFAS 106 OPEB - NH	Expense	Active
305010004100134	DEF FIT EXP-SFAS 106 OPEB - ME	Expense	Active
304010004100135	DEF FIT EXP-PENSION FAS 87 - NH	Expense	Active
305010004100135	DEF FIT EXP-PENSION FAS 87 - ME	Expense	Active
304010004100136	DEF FIT EXP-CIAC - NH	Expense	Active
305010004100136	DEF FIT EXP-CIAC - ME	Expense	Active
304010004100137	DEF FIT EXP-STOCK COMP - NH	Expense	Active
305010004100137	DEF FIT EXP-STOCK COMP - ME	Expense	Active
304010004100138	DEF FIT EXP-BAD DEBT - NH	Expense	Active
305010004100138	DEF FIT EXP-BAD DEBT - ME	Expense	Active
304010004100139	DEF FIT EXP-ACCRUED REVENUE - NH	Expense	Active
305010004100139	DEF FIT EXP-ACCRUED REVENUE - ME	Expense	Active
304010004100140	DEF FIT EXP-COMP SOFT AMORT - NH	Expense	Active
305010004100140	DEF FIT EXP-COMP SOFT AMORT - ME	Expense	Active
304010004100141	DEF FIT EXP-PREPAID PROP TAX - NH	Expense	Active
305010004100141	DEF FIT EXP-PREPAID PROP TAX - ME	Expense	Active
304010004100142	DEF FIT EXP-RATE CASE COSTS - NH	Expense	Active
305010004100142	DEF FIT EXP-RATE CASE COSTS - ME	Expense	Active
304010004100144	DEF FIT EXP-CATH PROTECT - NH	Expense	Active
305010004100144	DEF FIT EXP-CATH PROTECT - ME	Expense	Active
304010004100145	DEF FIT EXP-REMEDIATION - NH	Expense	Active
305010004100145	DEF FIT EXP-REMEDIATION - ME	Expense	Active
304010004100147	DEF FIT EXP-FAS87 REG ASSET - GAS - NH	Expense	Active
305010004100147	DEF FIT EXP-FAS87 REG ASSET - GAS - ME	Expense	Active
304010004100149	DEF FIT EXP-SFAS 106 REG ASSET - GAS - NH	Expense	Active
305010004100149	DEF FIT EXP-SFAS 106 REG ASSET - GAS - ME	Expense	Active
304010004100150	DEF FIT-BAD DEBT-REG ASSET - NH	Expense	Active
305010004100150	DEF FIT-BAD DEBT-REG ASSET - ME	Expense	Active
304010004100151	DEF FIT-TRANSITION COSTS - NH	Expense	Active
305010004100151	DEF FIT-TRANSITION COSTS - ME	Expense	Active
304010004100152	DEF FIT-TRANSACTION COSTS - NH	Expense	Active
305010004100152	DEF FIT-TRANSACTION COSTS - NH	Expense	Active
304010004100154	DEF FIT-PURCHASED DISCOUNT - NH	Expense	Active
305010004100154	DEF FIT-PURCHASED DISCOUNT - NH	Expense	Active
304010004100164	DEF FIT-MISC - NH	Expense	Active
305010004100164	DEF FIT-MISC - ME	Expense	Active
304010004100200	DEF SIT EXP- NH	Expense	Active
305010004100200	DEF SIT EXP- ME	Expense	Active
304010004100230	DEF SIT EXP-ACCEL DEPRECIATION-NH	Expense	Active
305010004100230	DEF SIT EXP-ACCEL DEPRECIATION-ME	Expense	Active

Account Code	Description	Type	Status
304010004100232	DEF SIT EXP-PRA - NH	Expense	Active
305010004100232	DEF SIT EXP-PRA - ME	Expense	Active
304010004100233	DEF SIT EXP-RETIREMENT LOSS - NH	Expense	Active
305010004100233	DEF SIT EXP-RETIREMENT LOSS - ME	Expense	Active
304010004100234	DEF SIT EXP-SFAS 106 OPEB - NH	Expense	Active
305010004100234	DEF SIT EXP-SFAS 106 OPEB - ME	Expense	Active
304010004100235	DEF SIT EXP-PENSION FAS 87 - NH	Expense	Active
305010004100235	DEF SIT EXP-PENSION FAS 87 - ME	Expense	Active
304010004100236	DEF SIT EXP-CIAC - NH	Expense	Active
305010004100236	DEF SIT EXP-CIAC - ME	Expense	Active
304010004100237	DEF SIT EXP-STOCK COMP - NH	Expense	Active
305010004100237	DEF SIT EXP-STOCK COMP - ME	Expense	Active
304010004100238	DEF SIT EXP-BAD DEBT - NH	Expense	Active
305010004100238	DEF SIT EXP-BAD DEBT - ME	Expense	Active
304010004100239	DEF SIT EXP-ACCRUED REVENUE - NH	Expense	Active
305010004100239	DEF SIT EXP-ACCRUED REVENUE - ME	Expense	Active
304010004100240	DEF SIT EXP-COMP SOFT AMORT - NH	Expense	Active
305010004100240	DEF SIT EXP-COMP SOFT AMORT - ME	Expense	Active
304010004100241	DEF SIT EXP-PREPAID PROP TAX - NH	Expense	Active
305010004100241	DEF SIT EXP-PREPAID PROP TAX - ME	Expense	Active
304010004100242	DEF SIT EXP-RATE CASE COSTS - NH	Expense	Active
305010004100242	DEF SIT EXP-RATE CASE COSTS - ME	Expense	Active
304010004100244	DEF SIT EXP-CATH PROTECT - NH	Expense	Active
305010004100244	DEF SIT EXP-CATH PROTECT - ME	Expense	Active
304010004100245	DEF SIT EXP-REMEDIATION - NH	Expense	Active
305010004100245	DEF SIT EXP-REMEDIATION - ME	Expense	Active
304010004100247	DEF SIT EXP-FAS 87 REG ASSET - GAS - NH	Expense	Active
305010004100247	DEF SIT EXP-FAS 87 REG ASSET - GAS - ME	Expense	Active
304010004100249	DEF SIT EXP-SFAS 106 REG ASSET - GAS - NH	Expense	Active
305010004100249	DEF SIT EXP-SFAS 106 REG ASSET - GAS - ME	Expense	Active
304010004100250	DEF SIT-BAD DEBT-REG ASSET - NH	Expense	Active
305010004100250	DEF SIT-BAD DEBT-REG ASSET - ME	Expense	Active
304010004100251	DEF SIT-TRANSITION COSTS - NH	Expense	Active
305010004100251	DEF SIT-TRANSITION COSTS - ME	Expense	Active
304010004100252	DEF SIT-TRANSACTION COSTS - NH	Expense	Active
305010004100252	DEF SIT-TRANSACTION COSTS - ME	Expense	Active
304010004100254	DEF SIT-PURCHASED DISCOUNT - NH	Expense	Active
305010004100254	DEF SIT-PURCHASED DISCOUNT - NH	Expense	Active
304010004100264	DEF SIT-MISC - NH	Expense	Active
305010004100264	DEF SIT-MISC - NH	Expense	Active
304010004110100	DEF FIT EXP - NH	Expense	Active
305010004110100	DEF FIT EXP - ME	Expense	Active
304010004110130	AMORT DEF FIT-CATH. PROTECT - NH	Expense	Active
305010004110130	AMORT DEF FIT-CATH. PROTECT - ME	Expense	Active
304010004110132	AMORT DEF FIT-PRA - NH	Expense	Active
305010004110132	AMORT DEF FIT-PRA - ME	Expense	Active
304010004110133	AMORT DEF FIT-RETIREMENT LOSS - NH	Expense	Active
305010004110133	AMORT DEF FIT-RETIREMENT LOSS - ME	Expense	Active
304010004110136	AMORT DEF FIT-CIAC DEPRN - NH	Expense	Active
305010004110136	AMORT DEF FIT-CIAC DEPRN - ME	Expense	Active
304010004110200	DEF SIT EXP - NH	Expense	Active
305010004110200	DEF SIT EXP - ME	Expense	Active
304010004110230	AMORT DEF SIT-CATH.PROTECT- NH	Expense	Active
305010004110230	AMORT DEF SIT-CATH.PROTECT - ME	Expense	Active
304010004110232	AMORT DEF SIT-PRA - NH	Expense	Active
305010004110232	AMORT DEF SIT-PRA - ME	Expense	Active
304010004110233	AMORT DEF SIT-RETIRMENT LOSS - NH	Expense	Active
305010004110233	AMORT DEF SIT-RETIRMENT LOSS - ME	Expense	Active
304010004110236	AMORT DEF SIT-CIAC DEPRN - NH	Expense	Active
305010004110236	AMORT DEF SIT-CIAC DEPRN - ME	Expense	Active
304010004117800	DEF FED TAX - REV DEP/AMORT	Expense	Active
305010004117800	DEF FED TAX - REV DEP/AMORT	Expense	Active
304010004117900	DEF STATE TAX - REV DEP/AMORT	Expense	Active
305010004117900	DEF STATE TAX - REV DEP/AMORT	Expense	Active

Account Code	Description	Type	Status
304008004120000	REVENUE FROM GAS PLANT LEASED TO OTHERS	Revenue	Active
305008004120000	REVENUE FROM GAS PLANT LEASED TO OTHERS	Revenue	Active
304080004150000	JOBBING REVENUE - NH	Revenue	Active
305085004150000	JOBBING REVENUE - ME	Revenue	Active
304080004150100	INSTLL ST BOILER-LABOR	Revenue	Active
304729514150100	ANNUAL INSPECTION REVENUE - NH	Revenue	Active
305085004150100	INSTLL ST BOILER-LABOR	Revenue	Active
305729514150100	CLEAN & CHECK RENTAL-REVENUE	Revenue	Active
304080004150200	INSTLL ST BOILER - PARTS	Revenue	Active
305085004150200	INSTLL ST BOILER - PARTS	Revenue	Active
304080004150300	MDSE DELIVERY-WH	Revenue	Active
305085004150300	MDSE DELIVERY-WH	Revenue	Active
304080004150400	MDSE INSTALL-PARTS	Revenue	Active
305085004150400	MDSE INSTALL-PARTS	Revenue	Active
304080004150500	MDSE INSTALL-LABOR	Revenue	Active
305085004150500	MDSE INSTALL-LABOR	Revenue	Active
305729514150500	CLEAN & CHECK RENTAL-BAD DEBT	Revenue	Active
304080004150600	MDSE ADMIN-WH	Revenue	Active
305085004150600	MDSE ADMIN-WH	Revenue	Active
304080004150700	INST HW BOILER - LABOR	Revenue	Active
305085004150700	INST HW BOILER - LABOR	Revenue	Active
304080004150800	INST HW (CORRECT O&M)	Revenue	Active
305085004150800	INST HW (CORRECT O&M)	Revenue	Active
304080004150900	INST HW BOILER - PARTS	Revenue	Active
305085004150900	INST HW BOILER - PARTS	Revenue	Active
304080004151000	INST B/F LABOR	Revenue	Active
305085004151000	INST B/F LABOR	Revenue	Active
304080004151100	INST FURNACE LABOR	Revenue	Active
305085004151100	INST FURNACE LABOR	Revenue	Active
304080004151200	MDSE GEN OPER-WH	Revenue	Active
305085004151200	MDSE GEN OPER-WH	Revenue	Active
304080004151300	MDSE GEN OPER(correct O&M)	Revenue	Active
305085004151300	MDSE GEN OPER(correct O&M)	Revenue	Active
304080004151400	INST FURNACE PARTS	Revenue	Active
305085004151400	INST FURNACE PARTS	Revenue	Active
304080004151500	MDSE INST B/F LB/PT	Revenue	Active
305085004151500	MDSE INST B/F LB/PT	Revenue	Active
304080004151600	MDSE BAD DEBTS-WH	Revenue	Active
305085004151600	MDSE BAD DEBTS-WH	Revenue	Active
304080004151700	MDSE INSTALL WTY-WH	Revenue	Active
305085004151700	MDSE INSTALL WTY-WH	Revenue	Active
304080004151800	NEWBUS EMPL INCEN PRG-INSTLLS	Revenue	Active
305085004151800	NEWBUS EMPL INCEN PRG-INSTLLS	Revenue	Active
304080004151900	MDSE SUPERVISION LBR	Revenue	Active
305085004151900	MDSE SUPERVISION LBR	Revenue	Active
304080004152000	MDSE P/R TAXES	Revenue	Active
305085004152000	MDSE P/R TAXES	Revenue	Active
304080004152100	MDSE P/R LIAB	Revenue	Active
305085004152100	MDSE P/R LIAB	Revenue	Active
304080004152200	MDSE PENSIONS	Revenue	Active
305085004152200	MDSE PENSIONS	Revenue	Active
304080004152300	MDSE GRP INSURANCE	Revenue	Active
305085004152300	MDSE GRP INSURANCE	Revenue	Active
304080004152400	MDSE FED INC TAX-WH	Revenue	Active
305085004152400	MDSE FED INC TAX-WH	Revenue	Active
304080004152500	MDSE MASS FRAN TAX-WH	Revenue	Active
305085004152500	MDSE MASS FRAN TAX-WH	Revenue	Active
304080004152600	MDSE INST ELEC A/C - LB/PRTS	Revenue	Active
305085004152600	MDSE INST ELEC A/C - LB/PRTS	Revenue	Active
304080004152700	RTL IN LB/PT C&I-NEW	Revenue	Active
305085004152700	RTL IN LB/PT C&I-NEW	Revenue	Active
304080004152800	MDSE FLEET EXP	Revenue	Active
305085004152800	MDSE FLEET EXP	Revenue	Active
304080004152900	MDSE STORES EXP	Revenue	Active

Account Code	Description	Type	Status
305085004152900	MDSE STORES EXP	Revenue	Active
304080004153000	MDSE NONPROD LBR	Revenue	Active
305085004153000	MDSE NONPROD LBR	Revenue	Active
304080004157000	JOBBING PARTS REVENUE - NH	Revenue	Active
305085004157000	JOBBING PARTS REVENUE - ME	Revenue	Active
304080004157100	JOBBING LABOR REVENUE - NH	Revenue	Active
304080544157100	EXCESS SERVICE LABOR - NH	Revenue	Active
305085004157100	JOBBING LABOR REVENUE - ME	Revenue	Active
305085544157100	EXCESS SERVICE LABOR - ME	Revenue	Active
304080004157200	DOVER HOUSING MASTER METER REVENUE	Revenue	Active
304080004157300	UNH REVENUE	Revenue	Active
304080004158000	JOBBING PARTS EXPENSE - NH	Expense	Active
305085004158000	JOBBING PARTS EXPENSE - ME	Expense	Active
304080004158100	JOBBING LABOR EXPENSE - NH	Expense	Active
305085004158100	JOBBING LABOR EXPENSE - ME	Expense	Active
304080004158200	MDSE COST OF APPL-WH	Expense	Active
305085004158200	MDSE COST OF APPL-WH	Expense	Active
304080004158300	MDSE CLERICAL SAL-WH	Expense	Active
305080004158300	MDSE CLERICAL SAL-WH	Expense	Active
305085004158300	MDSE CLERICAL SAL-WH	Expense	Active
304080004158400	MDSE LBR/PRT CB-WTY	Expense	Active
305085004158400	MDSE LBR/PRT CB-WTY	Expense	Active
304080004158500	EQUIPMENT TRAINING FEE FOR SERVICE	Expense	Active
305085004158500	SERVICE COUPON-INSTALLATION	Expense	Active
304080004160000	JOBBING EXPENSE - NH	Expense	Active
305085004160000	JOBBING EXPENSE - ME	Expense	Active
304080004160100	MDSE REV-CB Delivery	Expense	Active
305085004160100	MDSE REV-CB Delivery	Expense	Active
305085004160200	MDSE REV-INSTAL-CUST GENERATE	Expense	Active
305085004160300	MDSE REV - WORK ORDERS- PARTS	Expense	Active
305085004160400	INSTALL REV - CENTRAL HTG - LABOR	Expense	Active
304080004160500	INSTALL REV - CENTRAL HTG - PARTS	Expense	Active
305085004160500	INSTALL REV - CENTRAL HTG - PARTS	Expense	Active
304080004167200	DOVER HOUSING MASTER METER EXPENSE	Expense	Active
304080004167300	UNH EXPENSE	Expense	Active
305085004171300	NON UTIL-OTHER ALLOCATIONS	Expense	Active
305010004171400	NON UTILITY DEPRECIATION EXPENSE-ME	Expense	Active
305085004180000	NONUTILITY OPERATING RENTAL INCOME - ME	Revenue	Active
305729604180000	EQUIPMENT PROTECTION PLAN REVENUE - ME	Revenue	Active
304729564180100	NH EQUIP SALES - REVENUE	Revenue	Active
305729504180100	WATER HEATER RENTAL-REVENUE	Revenue	Active
305729524180100	CONVERSION BURNER RENTAL-REVENUE	Revenue	Active
305729534180100	EQUP PROTECTION PLAN	Revenue	Active
304729564180110	NH EQUIP SALES - PARTS & LABOR	Revenue	Active
305729504180200	NONUTILITY OP RENTAL INCOME - HH	Revenue	Active
305729504180300	NONUTILITY OP RENTAL INCOME - HH	Revenue	Active
304729504180500	WATER HEATER RENTAL BAD DEBT	Revenue	Active
304729514180500	CLEAN & CHECK REVENUE - BAD DEBT	Revenue	Active
304729524180500	CONVERSION BURNER RNTL BAD DEBT	Revenue	Active
304729534180500	EQUIP PROTECTION PLAN BAD DEBT	Revenue	Active
304729544180500	INTERIOR GAS LINE BAD DEBT	Revenue	Active
305729504180500	RNTL WH BAD DEBT - ME	Revenue	Active
305729524180500	CONV BURN BAD DEBT - ME	Revenue	Active
305729534180500	EQUP PROTECTION PLAN - BAD DEBT	Revenue	Active
300008004190000	INTEREST INCOME-MISC	Revenue	Active
304001104190000	INTEREST INCOME-DMD-COM-P-NH	Revenue	Active
304001134190000	INTEREST INCOME-WC-P-NH	Revenue	Active
304001144190000	INTEREST INCOME-BAD DEBT-P-NH	Revenue	Active
304001404190000	INTEREST INCOME-DMD-COM-OP-NH	Revenue	Active
304001434190000	INTEREST INCOME-WC-OP-NH	Revenue	Active
304001444190000	INTEREST INCOME-BAD DEBT-OP-NH	Revenue	Active
304001704190000	INT INC-SUP REF-DEMAND-NH	Revenue	Active
304001774190000	INTEREST INCOME-LIEAP-NH	Revenue	Active
304008004190000	INTEREST INCOME-MISC-NH	Revenue	Active

Account Code	Description	Type	Status
305001104190000	INTEREST INCOME-DMD-P-ME	Revenue	Active
305001134190000	INTEREST INCOME-WC-P-COM-ME	Revenue	Active
305001154190000	INTEREST INCOME-COM-P-ME	Revenue	Active
305001174190000	INTEREST INCOME-WC-P-DMD-ME	Revenue	Active
305001184190000	INTEREST INCOME-BAD DEBT-P-ME	Revenue	Active
305001404190000	INTEREST INCOME-DMD-OP-ME	Revenue	Active
305001434190000	INTEREST INCOME-WC-OP-COM-ME	Revenue	Active
305001454190000	INTEREST INCOME-COM-OP-ME	Revenue	Active
305001474190000	INTEREST INCOME-WC-OP-DMD-ME	Revenue	Active
305001484190000	INTEREST INCOME-BAD DEBT-OP-ME	Revenue	Active
305001704190000	INT INC-SUP REF-DEMAND-ME	Revenue	Active
305001714190000	INT INC-SUP REF-COMMOD-ME	Revenue	Active
305001764190000	INTEREST INCOME-INCOME-RLIAP	Revenue	Active
305008004190000	INTEREST INCOME-MISC-ME	Revenue	Active
304010134190099	WORKING CAPITAL - PEAK - NH	Revenue	Active
304010434190099	WORKING CAPITAL - OFF PEAK - NH	Revenue	Active
304910134190099	WORKING CAPITAL - PEAK - NH	Revenue	Active
304910434190099	WORKING CAPITAL - OFF PEAK - NH	Revenue	Active
305010134190099	WORKING CAPITAL - COM - PEAK - ME	Revenue	Active
305010174190099	WORKING CAPITAL - DMD - PEAK - ME	Revenue	Active
305010434190099	WORKING CAPITAL - COM - OFF PEAK - ME	Revenue	Active
305010474190099	WORKING CAPITAL - DMD - OFF PEAK - ME	Revenue	Active
305910134190099	WORKING CAPITAL - COMMODITY - PEAK - ME	Revenue	Active
305910174190099	WORKING CAPITAL - DEMAND - PEAK - ME	Revenue	Active
305910434190099	WORKING CAPITAL - COMMODITY - OFF PEAK - ME	Revenue	Active
305910474190099	WORKING CAPITAL - DEMAND - OFF PEAK - ME	Revenue	Active
300010004190100	AFUDC-OTHER FUNDS - COMMON	Revenue	Active
304010004190100	AFUDC-OTHER FUNDS - NH	Revenue	Active
305010004190100	AFUDC-OTHER FUNDS - ME	Revenue	Active
304008004190900	INT INC-OTHER - NH	Revenue	Active
305008004190900	INT INC-OTHER - ME	Revenue	Active
300008004190901	INT INC - CASH POOL - COMMON	Revenue	Active
304008004190901	INT INC - CASH POOL - NH	Revenue	Active
305008004190901	INT INC - CASH POOL - ME	Revenue	Active
304010004191000	FED I/T ON NON-UTIL INT INCOME	Revenue	Active
305010004191000	FED I/T ON NON-UTIL INT INCOME	Revenue	Active
304001724191005	INTEREST INCOME- LDAC EEC-NH	Revenue	Active
305001734191005	INTEREST INCOME - EERA-ME	Revenue	Active
305010004191100	MASS TAX ON NON-UTIL INTEREST	Revenue	Active
304010004191200	FED I/T ON LAND RENTAL INCOME	Revenue	Active
305010004191200	FED I/T ON LAND RENTAL INCOME	Revenue	Active
300008004210000	MISC NON OPER INCOME - COMMON	Revenue	Active
304008004210000	MISC NON OPER INCOME - NH	Revenue	Active
305008004210000	MISC NON OPER INCOME - ME	Revenue	Active
305001004210099	RECORD 10% ME PROFITS	Revenue	Active
300010004210100	GAIN OR LOSS ON DISP OF PROP - COMMON	Revenue	Active
304010004210100	GAIN OR LOSS ON DISP OF PROP - NH	Revenue	Active
305010004210100	GAIN OR LOSS ON DISP OF PROP - ME	Revenue	Active
304010004210200	CIAC GROSS UP	Expense	Active
305010004210200	CIAC GROSS UP	Expense	Active
304010004210300	CAP MITIGATION THRESHOLD SHARING	Expense	Active
305010004210300	CAP MITIGATION THRESHOLD SHARING	Expense	Active
304010004210400	LP-FLEET EXPENSE	Expense	Active
305010004210400	LP-FLEET EXPENSE	Expense	Active
304080004220000	MISC PROPANE SERVICE REV	Revenue	Active
305085004220000	MISC PROPANE SERVICE REV	Revenue	Active
300010004260000	PENALTIES - COMMON	Expense	Active
304010004260000	PENALTIES - NH	Expense	Active
305010004260000	PENALTIES - ME	Expense	Active
304003004260100	PENALTIES-NH	Expense	Active
305003004260100	PENALTIES-ME	Expense	Active
304010004260101	USC DONATIONS RECLASS	Expense	Active
305010004260101	USC DONATIONS RECLASS	Expense	Active
304010004260102	USC PENALTIES RECLASS	Expense	Active

Account Code	Description	Type	Status
305010004260102	USC PENALTIES RECLASS	Expense	Active
305024004260400	CIVIC ACTIVITIES - ME	Expense	Active
304010004260500	OTHER INCOME DEDUCTIONS - NH	Expense	Active
305010004260500	OTHER INCOME DEDUCTIONS - ME	Expense	Active
300001004261000	DONATIONS - COMMON	Expense	Active
300008004261000	DONATIONS - COMMON	Expense	Active
300021004261000	DONATIONS - COMMON	Expense	Active
300024004261000	COMMUNITY DONATIONS - COMMON	Expense	Active
300080004261000	DONATIONS - COMMON	Expense	Active
304001004261000	DONATIONS - NH	Expense	Active
304008004261000	DONATIONS - NH	Expense	Active
304021004261000	DONATIONS - NH	Expense	Active
304024004261000	COMMUNITY DONATIONS - NH	Expense	Active
304080004261000	DONATIONS - NH	Expense	Active
305001004261000	DONATIONS - ME	Expense	Active
305008004261000	DONATIONS - ME	Expense	Active
305021004261000	DONATIONS - ME	Expense	Active
305024004261000	COMMUNITY DONATIONS - ME	Expense	Active
305085004261000	DONATIONS - ME	Expense	Active
304802004261300	ADVERTISING - NH	Expense	Active
304829004261300	ADVERTISING - NH	Expense	Active
305802004261300	ADVERTISING - ME	Expense	Active
305829004261300	ADVERTISING - ME	Expense	Active
304802004261400	MARKET DEVELOPMENT - GENERAL - NH	Expense	Active
304829004261400	MARKET DEVELOPMENT - GENERAL - NH	Expense	Active
305802004261400	MARKET DEVELOPMENT - GENERAL - ME	Expense	Active
305829004261400	MARKET DEVELOPMENT - GENERAL - ME	Expense	Active
304802004261500	VISIBILITY - NH	Expense	Active
304829004261500	VISIBILITY - NH	Expense	Active
305802004261500	VISIBILITY - ME	Expense	Active
305829004261500	VISIBILITY - ME	Expense	Active
300024004261600	COMMUNITY SPONSORSHIPS - COMMON	Expense	Active
304024004261600	COMMUNITY SPONSORSHIPS - NH	Expense	Active
305024004261600	COMMUNITY SPONSORSHIPS - ME	Expense	Active
300024004261700	OUTREACH AND EDUCATION - COMMON	Expense	Active
304024004261700	OUTREACH AND EDUCATION - NH	Expense	Active
305024004261700	OUTREACH AND EDUCATION - ME	Expense	Active
304010004261800	RECONCILIATION ADJUSTMENTS	Expense	Active
305010004261800	RECONCILIATION ADJUSTMENTS	Expense	Active
304010004261900	DOT / DPU FEES/ASSESSMENTS	Expense	Active
305010004261900	DOT / DPU FEES/ASSESSMENTS	Expense	Active
304010004262000	NIPSCO AMORTIZATION	Expense	Active
305010004262000	NIPSCO AMORTIZATION	Expense	Active
304010004262100	SQI METER TO CASH	Expense	Active
305010004262100	SQI METER TO CASH	Expense	Active
300008004270000	INTEREST ON LT DEBT - COMMON	Expense	Active
304008004270000	INTEREST ON LT DEBT - NH	Expense	Active
305008004270000	INTEREST ON LT DEBT - ME	Expense	Active
300008004280000	AMORT OF DEBT EXPENSE - COMMON	Expense	Active
304008004280000	AMORT OF DEBT EXPENSE - NH	Expense	Active
305008004280000	AMORT OF DEBT EXPENSE - ME	Expense	Active
300008004300000	INTEREST EXPENSE - ASSOC. CO. - COMMON	Expense	Active
304008004300000	INTEREST EXPENSE - ASSOC. CO. - NH	Expense	Active
305008004300000	INTEREST EXPENSE - ASSOC. CO. - ME	Expense	Active
300008004310000	OTHER INTEREST EXPENSE - COMMON	Expense	Active
304001104310000	INTEREST EXPENSE	Expense	Active
304001134310000	INTEREST EXPENSE	Expense	Active
304001144310000	INTEREST EXPENSE	Expense	Active
304001404310000	INTEREST EXPENSE	Expense	Active
304001434310000	INTEREST EXPENSE	Expense	Active
304001444310000	INTEREST EXPENSE	Expense	Active
304001704310000	INT EXP-SUP REF-DEMAND-NH	Expense	Active
304001774310000	INTEREST EXPENSE	Expense	Active
304008004310000	OTHER INTEREST EXPENSE - NH	Expense	Active

Account Code	Description	Type	Status
305001104310000	INTEREST EXPENSE-DMD-P-ME	Expense	Active
305001134310000	INTEREST EXPENSE-WC-P-COM-ME	Expense	Active
305001154310000	INTEREST EXPENSE-COM-P-ME	Expense	Active
305001174310000	INTEREST EXPENSE-WC-P-DMD-ME	Expense	Active
305001184310000	INTEREST EXPENSE-BAD DEBT-P-ME	Expense	Active
305001404310000	INTEREST EXPENSE	Expense	Active
305001434310000	INTEREST EXPENSE-WC-OP-COM-ME	Expense	Active
305001454310000	INTEREST EXPENSE-COM-OP-ME	Expense	Active
305001474310000	INTEREST EXPENSE-WC-OP-DMD-ME	Expense	Active
305001484310000	INTEREST EXPENSE	Expense	Active
305001704310000	INT EXP-SUP REF-DEMAND-ME	Expense	Active
305001714310000	INT EXP-SUP REF-COMMOD-ME	Expense	Active
305002004310000	ENERGY EFFICIENCY TRUST INT EXP	Expense	Active
305008004310000	OTHER INTEREST EXPENSE - ME	Expense	Active
304001004310099	INVENTORY FINANCE CHARGES - PEAK - NH	Expense	Active
304901114310099	INVENTORY FINANCE CHARGES - PEAK - NH	Expense	Active
304901414310099	NH INTEREST ON FINANCED INVENTORY OFF PEAK	Expense	Active
305001004310099	INVENTORY FINANCE CHARGES - PEAK - ME	Expense	Active
305901154310099	INVENTORY FINANCE CHARGES - PEAK - ME	Expense	Active
305901454310099	ME INTEREST ON FINANCED INVENTORY OFF PEAK	Expense	Active
304021004310400	INTEREST ON CUSTOMER DEPOSITS - NH	Expense	Active
305021004310400	INTEREST ON CUSTOMER DEPOSITS - ME	Expense	Active
304001724311005	INTEREST EXPENSE- LDAC EEC	Expense	Active
305001734311005	INTEREST EXPENSE --EERA- ME	Expense	Active
300008004313000	INT EXP-LEASES - COMMON	Expense	Active
304008004313000	INT EXP-LEASES - NH	Expense	Active
305008004313000	INT EXP-LEASES - ME	Expense	Active
304008004313100	DEFERRED COMPENSATION INTEREST	Expense	Active
305008004313100	DEFERRED COMPENSATION INTEREST	Expense	Active
304008004313200	INT EXP-NON COMPETE LIABILITY	Expense	Active
305008004313200	INT EXP-NON COMPETE LIABILITY	Expense	Active
300010004320000	AFUDC-BORROWED FUNDS - COMMON	Expense	Active
304010004320000	AFUDC-BORROWED FUNDS - NH	Expense	Active
305010004320000	AFUDC-BORROWED FUNDS - ME	Expense	Active
300008004380000	DIV DECLARED COMMON STK	Expense	Active
304008004380000	DIV DECLARED COMMON STK -NH	Expense	Active
305008004380000	DIV DECLARED COMMON STK -ME	Expense	Active
300010004390000	ADJMNTS TO RETAINED EARNINGS	Expense	Active
304008004540000	MISC RENT - NH	Revenue	Active
305008004540000	MISC RENT - ME	Revenue	Active
304008004570001	RENTAL INCOME - GRANITE	Revenue	Active
305008004570001	RENTAL INCOME - GRANITE	Revenue	Active
304008004570002	RENTAL INCOME - USOURCE	Revenue	Active
304008004570003	RENTAL INCOME - USC	Revenue	Active
304008004800101	RESIDENTIAL R6R11 SALES - NH	Revenue	Active
304008014800101	R-6 W-NEXT-Customer Charge	Revenue	Active
304008024800101	R-6 W-NEXT-First Step	Revenue	Active
304008034800101	R-6 W-NEXT-Excess	Revenue	Active
304008064800101	R-6 S-NEXT-Customer Charge	Revenue	Active
304008074800101	R-6 S-NEXT-First Step	Revenue	Active
304008084800101	R-6 S-NEXT-Excess	Revenue	Active
304901104800101	R-6 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114800101	R-6 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124800101	R-6 W-NEXT-Reconciliation Costs	Revenue	Active
304901134800101	R-6 W-NEXT-Working Capital Allowance	Revenue	Active
304901144800101	R-6 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154800101	R-6 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164800101	R-6 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174800101	R-6 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404800101	R-6 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414800101	R-6 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424800101	R-6 S-NEXT-Reconciliation Costs	Revenue	Active
304901434800101	R-6 S-NEXT-Working Capital Allowance	Revenue	Active
304901444800101	R-6 S-NEXT-Bad Debt Allowance	Revenue	Active

Account Code	Description	Type	Status
304901454800101	R-6 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464800101	R-6 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474800101	R-6 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704800101	R-6 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714800101	R-6 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724800101	R-6 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734800101	R-6 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744800101	R-6 W-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754800101	R-6 S-NEXT-Wells LNG	Revenue	Active
304901774800101	R-6 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784800101	R-6 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794800101	R-6 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004800101	R1 NU Converted Revenue	Revenue	Active
305008014800101	R-1-W-NEXT Customer Charge	Revenue	Active
305008024800101	R-1-W-NEXT First Step	Revenue	Active
305008034800101	R-1-W-NEXT Excess	Revenue	Active
305008064800101	R-1-S-NEXT Customer Charge	Revenue	Active
305008074800101	R-1-S-NEXT First Step	Revenue	Active
305008084800101	R-1-S-NEXT Excess	Revenue	Active
305901104800101	R-1-W-NEXT Demand COG	Revenue	Active
305901114800101	R-1-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124800101	R-1-W-NEXT LPG & LNG Storage	Revenue	Active
305901134800101	R-1-W-NEXT Working Capital Commodity	Revenue	Active
305901144800101	R-1-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154800101	R-1-W-NEXT Commodity COG	Revenue	Active
305901164800101	R-1-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174800101	R-1-W-NEXT Working Capital Demand	Revenue	Active
305901184800101	R-1-W-NEXT Bad Debt	Revenue	Active
305901404800101	R-1-S-NEXT Demand COG	Revenue	Active
305901414800101	R-1-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424800101	R-1-S-NEXT LPG & LNG Storage	Revenue	Active
305901434800101	R-1-S-NEXT Working Capital Commodity	Revenue	Active
305901444800101	R-1-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454800101	R-1-S-NEXT Commodity COG	Revenue	Active
305901464800101	R-1-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474800101	R-1-S-NEXT Working Capital Demand	Revenue	Active
305901484800101	R-1-S-NEXT Bad Debt	Revenue	Active
305901704800101	R-1-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714800101	R-1-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724800101	R-1-NEXT WELLS SURCHARGE	Revenue	Active
305901734800101	R-1-S-NEXT EERA	Revenue	Active
305901744800101	R-1-S-NEXT ERC	Revenue	Active
305901764800101	R1 LOW INCOME CREDIT DISCOUNT	Revenue	Active
304008004800102	R-11 NU CONVERTED REVENUE	Revenue	Active
304008014800102	R-11 W-NEXT-Customer Charge	Revenue	Active
304008024800102	R-11 W-NEXT-First Step	Revenue	Active
304008034800102	R-11 W-NEXT-Excess	Revenue	Active
304008064800102	R-11 S-NEXT-Customer Charge	Revenue	Active
304008074800102	R-11 S-NEXT-First Step	Revenue	Active
304008084800102	R-11 S-NEXT-Excess	Revenue	Active
304901104800102	R-11 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114800102	R-11 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124800102	R-11 W-NEXT-Reconciliation Costs	Revenue	Active
304901134800102	R-11 W-NEXT-Working Capital Allowance	Revenue	Active
304901144800102	R-11 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154800102	R-11 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164800102	R-11 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174800102	R-11 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404800102	R-11 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414800102	R-11 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424800102	R-11 S-NEXT-Reconciliation Costs	Revenue	Active
304901434800102	R-11 S-NEXT-Working Capital Allowance	Revenue	Active
304901444800102	R-11 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454800102	R-11 S-NEXT-Miscellaneous Overhead	Revenue	Active

Account Code	Description	Type	Status
304901464800102	R-11 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474800102	R-11 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704800102	R-11 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714800102	R-11 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724800102	R-11 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734800102	R-11 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744800102	R-11 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754800102	R-11 S-NEXT-Wells LNG	Revenue	Active
304901774800102	R-11 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784800102	R-11 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794800102	R-11 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
304008004800201	R5 NU Converted Revenue	Revenue	Active
304008014800201	R-5 W-NEXT-Customer Charge	Revenue	Active
304008024800201	R-5 W-NEXT-First Step	Revenue	Active
304008034800201	R-5 W-NEXT-Excess	Revenue	Active
304008064800201	R-5 S-NEXT-Customer Charge	Revenue	Active
304008074800201	R-5 S-NEXT-First Step	Revenue	Active
304008084800201	R-5 S-NEXT-Excess	Revenue	Active
304901104800201	R-5 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114800201	R-5 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124800201	R-5 W-NEXT-Reconciliation Costs	Revenue	Active
304901134800201	R-5 W-NEXT-Working Capital Allowance	Revenue	Active
304901144800201	R-5 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154800201	R-5 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164800201	R-5 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174800201	R-5 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404800201	R-5 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414800201	R-5 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424800201	R-5 S-NEXT-Reconciliation Costs	Revenue	Active
304901434800201	R-5 S-NEXT-Working Capital Allowance	Revenue	Active
304901444800201	R-5 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454800201	R-5 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464800201	R-5 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474800201	R-5 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901484800201	R-5 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704800201	R-5 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714800201	R-5 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724800201	R-5 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734800201	R-5 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744800201	R-5 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754800201	R-5 S-NEXT-Wells LNG	Revenue	Active
304901774800201	R-5 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784800201	R-5 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794800201	R-5 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004800201	R2 NU Converted Revenue	Revenue	Active
305008014800201	R-2-W-NEXT Customer Charge	Revenue	Active
305008024800201	R-2-W-NEXT First Step	Revenue	Active
305008034800201	R-2-W-NEXT Excess	Revenue	Active
305008064800201	R-2-S-NEXT Customer Charge	Revenue	Active
305008074800201	R-2-S-NEXT First Step	Revenue	Active
305008084800201	R-2-S-NEXT Excess	Revenue	Active
305901104800201	R-2-W-NEXT Demand COG	Revenue	Active
305901114800201	R-2-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124800201	R-2-W-NEXT LPG & LNG Storage	Revenue	Active
305901134800201	R-2-W-NEXT Working Capital Commodity	Revenue	Active
305901144800201	R-2-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154800201	R-2-W-NEXT Commodity COG	Revenue	Active
305901164800201	R-2-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174800201	R-2-W-NEXT Working Capital Demand	Revenue	Active
305901184800201	R-2-W-NEXT Bad Debt	Revenue	Active
305901404800201	R-2-S-NEXT Demand COG	Revenue	Active
305901414800201	R-2-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424800201	R-2-S-NEXT LPG & LNG Storage	Revenue	Active
305901434800201	R-2-S-NEXT Working Capital Commodity	Revenue	Active

Account Code	Description	Type	Status
305901444800201	R-2-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454800201	R-2-S-NEXT Commodity COG	Revenue	Active
305901464800201	R-2-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474800201	R-2-S-NEXT Working Capital Demand	Revenue	Active
305901484800201	R-2-S-NEXT Bad Debt	Revenue	Active
305901704800201	R-2-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714800201	R-2-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724800201	R-2-NEXT WELLS SURCHARGE	Revenue	Active
305901734800201	R-2-S-NEXT EERA	Revenue	Active
305901744800201	R-2-S-NEXT ERC	Revenue	Active
305901764800201	R2 LOW INCOME CREDIT DISCOUNT	Revenue	Active
304008004800202	R-10 NU CONVERTED REVENUE	Revenue	Active
304008014800202	R-10 W-NEXT-Customer Charge	Revenue	Active
304008024800202	R-10 W-NEXT-First Step	Revenue	Active
304008034800202	R-10 W-NEXT-Excess	Revenue	Active
304008064800202	R-10 S-NEXT-Customer Charge	Revenue	Active
304008074800202	R-10 S-NEXT-First Step	Revenue	Active
304008084800202	R-10 S-NEXT-Excess	Revenue	Active
304901104800202	R-10 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114800202	R-10 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124800202	R-10 W-NEXT-Reconciliation Costs	Revenue	Active
304901134800202	R-10 W-NEXT-Working Capital Allowance	Revenue	Active
304901144800202	R-10 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154800202	R-10 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164800202	R-10 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174800202	R-10 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404800202	R-10 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414800202	R-10 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424800202	R-10 S-NEXT-Reconciliation Costs	Revenue	Active
304901434800202	R-10 S-NEXT-Working Capital Allowance	Revenue	Active
304901444800202	R-10 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454800202	R-10 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464800202	R-10 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474800202	R-10 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704800202	R-10 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714800202	R-10 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724800202	R-10 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734800202	R-10 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744800202	R-10 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754800202	R-10 S-NEXT-Wells LNG	Revenue	Active
304901774800202	R-10 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784800202	R-10 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794800202	R-10 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
304008004810000	Commercial Tariff Normalization	Revenue	Active
305008004810000	Commercial Tariff Normalization	Revenue	Active
304008004810101	G40 NU Converted Revenue	Revenue	Active
304008014810101	G-40 W-NEXT-Customer Charge	Revenue	Active
304008024810101	G-40 W-NEXT-First Step	Revenue	Active
304008034810101	G-40 W-NEXT-Excess	Revenue	Active
304008064810101	G-40 S-NEXT-Customer Charge	Revenue	Active
304008074810101	G-40 S-NEXT-First Step	Revenue	Active
304008084810101	G-40 S-NEXT-Excess	Revenue	Active
304901104810101	G-40 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114810101	G-40 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124810101	G-40 W-NEXT-Reconciliation Costs	Revenue	Active
304901134810101	G-40 W-NEXT-Working Capital Allowance	Revenue	Active
304901144810101	G-40 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154810101	G-40 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164810101	G-40 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174810101	G-40 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404810101	G-40 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414810101	G-40 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424810101	G-40 S-NEXT-Reconciliation Costs	Revenue	Active
304901434810101	G-40 S-NEXT-Working Capital Allowance	Revenue	Active

Account Code	Description	Type	Status
304901444810101	G-40 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454810101	G-40 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464810101	G-40 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474810101	G-40 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704810101	G-40 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714810101	G-40 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724810101	G-40 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734810101	G-40 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744810101	G-40 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754810101	G-40 S-NEXT-Wells LNG	Revenue	Active
304901764810101	G-40 S-NEXT-CCE (Customer Choice Expense)	Revenue	Active
304901774810101	G-40 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784810101	G-40 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794810101	G-40 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004810101	G40- NU Converted Revenue	Revenue	Active
305008014810101	G-40-W-NEXT Customer Charge	Revenue	Active
305008024810101	G-40-W-NEXT First Step	Revenue	Active
305008034810101	G-40-W-NEXT Excess	Revenue	Active
305008064810101	G-40-S-NEXT Customer Charge	Revenue	Active
305008074810101	G-40-S-NEXT First Step	Revenue	Active
305008084810101	G-40-S-NEXT Excess	Revenue	Active
305901104810101	G-40-W-NEXT Demand COG	Revenue	Active
305901114810101	G-40-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124810101	G-40-W-NEXT LPG & LNG Storage	Revenue	Active
305901134810101	G-40-W-NEXT Working Capital Commodity	Revenue	Active
305901144810101	G-40-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154810101	G-40-W-NEXT Commodity COG	Revenue	Active
305901164810101	G-40-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174810101	G-40-W-NEXT Working Capital Demand	Revenue	Active
305901184810101	G-40-W-NEXT Bad Debt	Revenue	Active
305901404810101	G-40-S-NEXT Demand COG	Revenue	Active
305901414810101	G-40-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424810101	G-40-S-NEXT LPG & LNG Storage	Revenue	Active
305901434810101	G-40-S-NEXT Working Capital Commodity	Revenue	Active
305901444810101	G-40-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454810101	G-40-S-NEXT Commodity COG	Revenue	Active
305901464810101	G-40-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474810101	G-40-S-NEXT Working Capital Demand	Revenue	Active
305901484810101	G-40-S-NEXT Bad Debt	Revenue	Active
305901704810101	G-40-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714810101	G-40-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724810101	G-40-NEXT WELLS SURCHARGE	Revenue	Active
305901734810101	G-40-S-NEXT EERA	Revenue	Active
305901744810101	G-40-S-NEXT ERC	Revenue	Active
304008004810102	G50 NU CONVERTED REVENUE	Revenue	Active
304008014810102	G-50 W-NEXT-Customer Charge	Revenue	Active
304008024810102	G-50 W-NEXT-First Step	Revenue	Active
304008034810102	G-50 W-NEXT-Excess	Revenue	Active
304008064810102	G-50 S-NEXT-Customer Charge	Revenue	Active
304008074810102	G-50 S-NEXT-First Step	Revenue	Active
304008084810102	G-50 S-NEXT-Excess	Revenue	Active
304901104810102	G-50 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114810102	G-50 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124810102	G-50 W-NEXT-Reconciliation Costs	Revenue	Active
304901134810102	G-50 W-NEXT-Working Capital Allowance	Revenue	Active
304901144810102	G-50 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154810102	G-50 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164810102	G-50 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174810102	G-50 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404810102	G-50 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414810102	G-50 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424810102	G-50 S-NEXT-Reconciliation Costs	Revenue	Active
304901434810102	G-50 S-NEXT-Working Capital Allowance	Revenue	Active
304901444810102	G-50 S-NEXT-Bad Debt Allowance	Revenue	Active

Account Code	Description	Type	Status
304901454810102	G-50 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464810102	G-50 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474810102	G-50 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704810102	G-50 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714810102	G-50 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724810102	G-50 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734810102	G-50 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744810102	G-50 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754810102	G-50 S-NEXT-Wells LNG	Revenue	Active
304901764810102	G-50 S-NEXT-CCE (Customer Choice Expense)	Revenue	Active
304901774810102	G-50 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784810102	G-50 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794810102	G-50 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004810102	G50 NU Converted Revenue	Revenue	Active
305008014810102	G-50-W-NEXT Customer Charge	Revenue	Active
305008024810102	G-50-W-NEXT First Step	Revenue	Active
305008034810102	G-50-W-NEXT Excess	Revenue	Active
305008064810102	G-50-S-NEXT Customer Charge	Revenue	Active
305008074810102	G-50-S-NEXT First Step	Revenue	Active
305008084810102	G-50-S-NEXT Excess	Revenue	Active
305901104810102	G-50-W-NEXT Demand COG	Revenue	Active
305901114810102	G-50-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124810102	G-50-W-NEXT LPG & LNG Storage	Revenue	Active
305901134810102	G-50-W-NEXT Working Capital Commodity	Revenue	Active
305901144810102	G-50-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154810102	G-50-W-NEXT Commodity COG	Revenue	Active
305901164810102	G-50-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174810102	G-50-W-NEXT Working Capital Demand	Revenue	Active
305901184810102	G-50-W-NEXT Bad Debt	Revenue	Active
305901404810102	G-50-S-NEXT Demand COG	Revenue	Active
305901414810102	G-50-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424810102	G-50-S-NEXT LPG & LNG Storage	Revenue	Active
305901434810102	G-50-S-NEXT Working Capital Commodity	Revenue	Active
305901444810102	G-50-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454810102	G-50-S-NEXT Commodity COG	Revenue	Active
305901464810102	G-50-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474810102	G-50-S-NEXT Working Capital Demand	Revenue	Active
305901484810102	G-50-S-NEXT Bad Debt	Revenue	Active
305901704810102	G-50-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714810102	G-50-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724810102	G-50-NEXT WELLS SURCHARGE	Revenue	Active
305901734810102	G-50-S-NEXT EERA	Revenue	Active
305901744810102	G-50-S-NEXT ERC	Revenue	Active
304008004810201	G-41 NU CONVERTED REVENUE	Revenue	Active
304008014810201	G-41 W-NEXT-Customer Charge	Revenue	Active
304008024810201	G-41 W-NEXT-First Step	Revenue	Active
304008064810201	G-41 S-NEXT-Customer Charge	Revenue	Active
304008074810201	G-41 S-NEXT-First Step	Revenue	Active
304901104810201	G-41 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114810201	G-41 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124810201	G-41 W-NEXT-Reconciliation Costs	Revenue	Active
304901134810201	G-41 W-NEXT-Working Capital Allowance	Revenue	Active
304901144810201	G-41 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154810201	G-41 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164810201	G-41 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174810201	G-41 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404810201	G-41 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414810201	G-41 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424810201	G-41 S-NEXT-Reconciliation Costs	Revenue	Active
304901434810201	G-41 S-NEXT-Working Capital Allowance	Revenue	Active
304901444810201	G-41 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454810201	G-41 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464810201	G-41 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474810201	G-41 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active

Account Code	Description	Type	Status
304901704810201	G-41 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714810201	G-41 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724810201	G-41 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734810201	G-41 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744810201	G-41 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754810201	G-41 S-NEXT-Wells LNG	Revenue	Active
304901764810201	G-41 S-NEXT-CCE (Customer Choice Expense)	Revenue	Active
304901774810201	G-41 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784810201	G-41 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794810201	G-41 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004810201	G41 NU Converted Revenue	Revenue	Active
305008014810201	G-41-W-NEXT Customer Charge	Revenue	Active
305008024810201	G-41-W-NEXT First Step	Revenue	Active
305008034810201	G-41-W-NEXT Excess	Revenue	Active
305008064810201	G-41-S-NEXT Customer Charge	Revenue	Active
305008074810201	G-41-S-NEXT First Step	Revenue	Active
305008084810201	G-41-S-NEXT Excess	Revenue	Active
305901104810201	G-41-W-NEXT Demand COG	Revenue	Active
305901114810201	G-41-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124810201	G-41-W-NEXT LPG & LNG Storage	Revenue	Active
305901134810201	G-41-W-NEXT Working Capital Commodity	Revenue	Active
305901144810201	G-41-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154810201	G-41-W-NEXT Commodity COG	Revenue	Active
305901164810201	G-41-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174810201	G-41-W-NEXT Working Capital Demand	Revenue	Active
305901184810201	G-41-W-NEXT Bad Debt	Revenue	Active
305901404810201	G-41-S-NEXT Demand COG	Revenue	Active
305901414810201	G-41-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424810201	G-41-S-NEXT LPG & LNG Storage	Revenue	Active
305901434810201	G-41-S-NEXT Working Capital Commodity	Revenue	Active
305901444810201	G-41-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454810201	G-41-S-NEXT Commodity COG	Revenue	Active
305901464810201	G-41-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474810201	G-41-S-NEXT Working Capital Demand	Revenue	Active
305901484810201	G-41-S-NEXT Bad Debt	Revenue	Active
305901704810201	G-41-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714810201	G-41-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724810201	G-41-NEXT WELLS SURCHARGE	Revenue	Active
305901734810201	G-41-S-NEXT EERA	Revenue	Active
305901744810201	G-41-S-NEXT ERC	Revenue	Active
304008004810202	G51 NU Converted Revenue	Revenue	Active
304008014810202	G-51 W-NEXT-Customer Charge	Revenue	Active
304008024810202	G-51 W-NEXT-First Step	Revenue	Active
304008034810202	G-51 W-NEXT-Excess	Revenue	Active
304008064810202	G-51 S-NEXT-Customer Charge	Revenue	Active
304008074810202	G-51 S-NEXT-First Step	Revenue	Active
304008084810202	G-51 S-NEXT-Excess	Revenue	Active
304901104810202	G-51 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114810202	G-51 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124810202	G-51 W-NEXT-Reconciliation Costs	Revenue	Active
304901134810202	G-51 W-NEXT-Working Capital Allowance	Revenue	Active
304901144810202	G-51 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154810202	G-51 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164810202	G-51 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174810202	G-51 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404810202	G-51 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414810202	G-51 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424810202	G-51 S-NEXT-Reconciliation Costs	Revenue	Active
304901434810202	G-51 S-NEXT-Working Capital Allowance	Revenue	Active
304901444810202	G-51 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454810202	G-51 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464810202	G-51 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474810202	G-51 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704810202	G-51 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active

Account Code	Description	Type	Status
304901714810202	G-51 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724810202	G-51 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734810202	G-51 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744810202	G-51 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754810202	G-51 S-NEXT-Wells LNG	Revenue	Active
304901764810202	G-51 S-NEXT-CCE (Customer Choice Expense)	Revenue	Active
304901774810202	G-51 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784810202	G-51 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794810202	G-51 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004810202	G51 NU Converted Revenue	Revenue	Active
305008014810202	G-51-W-NEXT Customer Charge	Revenue	Active
305008024810202	G-51-W-NEXT First Step	Revenue	Active
305008034810202	G-51-W-NEXT Excess	Revenue	Active
305008064810202	G-51-S-NEXT Customer Charge	Revenue	Active
305008074810202	G-51-S-NEXT First Step	Revenue	Active
305008084810202	G-51-S-NEXT Excess	Revenue	Active
305901104810202	G-51-W-NEXT Demand COG	Revenue	Active
305901114810202	G-51-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124810202	G-51-W-NEXT LPG & LNG Storage	Revenue	Active
305901134810202	G-51-W-NEXT Working Capital Commodity	Revenue	Active
305901144810202	G-51-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154810202	G-51-W-NEXT Commodity COG	Revenue	Active
305901164810202	G-51-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174810202	G-51-W-NEXT Working Capital Demand	Revenue	Active
305901184810202	G-51-W-NEXT Bad Debt	Revenue	Active
305901404810202	G-51-S-NEXT Demand COG	Revenue	Active
305901414810202	G-51-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424810202	G-51-S-NEXT LPG & LNG Storage	Revenue	Active
305901434810202	G-51-S-NEXT Working Capital Commodity	Revenue	Active
305901444810202	G-51-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454810202	G-51-S-NEXT Commodity COG	Revenue	Active
305901464810202	G-51-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474810202	G-51-S-NEXT Working Capital Demand	Revenue	Active
305901484810202	G-51-S-NEXT Bad Debt	Revenue	Active
305901704810202	G-51-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714810202	G-51-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724810202	G-51-NEXT WELLS SURCHARGE	Revenue	Active
305901734810202	G-51-S-NEXT EERA	Revenue	Active
305901744810202	G-51-S-NEXT ERC	Revenue	Active
304008004810301	G42 NU Converted Revenue	Revenue	Active
304008014810301	G-42 W-NEXT-Customer Charge	Revenue	Active
304008024810301	G-42 W-NEXT-First Step	Revenue	Active
304008064810301	G-42 S-NEXT-Customer Charge	Revenue	Active
304008074810301	G-42 S-NEXT-First Step	Revenue	Active
304901104810301	G-42 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114810301	G-42 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124810301	G-42 W-NEXT-Reconciliation Costs	Revenue	Active
304901134810301	G-42 W-NEXT-Working Capital Allowance	Revenue	Active
304901144810301	G-42 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154810301	G-42 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164810301	G-42 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174810301	G-42 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404810301	G-42 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414810301	G-42 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424810301	G-42 S-NEXT-Reconciliation Costs	Revenue	Active
304901434810301	G-42 S-NEXT-Working Capital Allowance	Revenue	Active
304901444810301	G-42 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454810301	G-42 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464810301	G-42 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474810301	G-42 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704810301	G-42 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714810301	G-42 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724810301	G-42 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734810301	G-42 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active

Account Code	Description	Type	Status
304901744810301	G-42 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754810301	G-42 S-NEXT-Wells LNG	Revenue	Active
304901764810301	G-42 S-NEXT-CCE (Customer Choice Expense)	Revenue	Active
304901774810301	G-42 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784810301	G-42 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794810301	G-42 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004810301	G42 NU Converted Revenue	Revenue	Active
305008014810301	G-42-W-NEXT Customer Charge	Revenue	Active
305008024810301	G-42-W-NEXT First Step	Revenue	Active
305008034810301	G-42-W-NEXT Excess	Revenue	Active
305008064810301	G-42-S-NEXT Customer Charge	Revenue	Active
305008074810301	G-42-S-NEXT First Step	Revenue	Active
305008084810301	G-42-S-NEXT Excess	Revenue	Active
305901104810301	G-42-W-NEXT Demand COG	Revenue	Active
305901114810301	G-42-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124810301	G-42-W-NEXT LPG & LNG Storage	Revenue	Active
305901134810301	G-42-W-NEXT Working Capital Commodity	Revenue	Active
305901144810301	G-42-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154810301	G-42-W-NEXT Commodity COG	Revenue	Active
305901164810301	G-42-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174810301	G-42-W-NEXT Working Capital Demand	Revenue	Active
305901184810301	G-42-W-NEXT Bad Debt	Revenue	Active
305901404810301	G-42-S-NEXT Demand COG	Revenue	Active
305901414810301	G-42-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424810301	G-42-S-NEXT LPG & LNG Storage	Revenue	Active
305901434810301	G-42-S-NEXT Working Capital Commodity	Revenue	Active
305901444810301	G-42-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454810301	G-42-S-NEXT Commodity COG	Revenue	Active
305901464810301	G-42-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474810301	G-42-S-NEXT Working Capital Demand	Revenue	Active
305901484810301	G-42-S-NEXT Bad Debt	Revenue	Active
305901704810301	G-42-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714810301	G-42-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724810301	G-42-S-NEXT Wells Surcharge	Revenue	Active
305901734810301	G-42-S-NEXT EERA	Revenue	Active
305901744810301	G-42-S-NEXT ERC	Revenue	Active
304008004810302	G52 NU Converted Revenue	Revenue	Active
304008014810302	G-52 W-NEXT-Customer Charge	Revenue	Active
304008024810302	G-52 W-NEXT-First Step	Revenue	Active
304008064810302	G-52 S-NEXT-Customer Charge	Revenue	Active
304008074810302	G-52 S-NEXT-First Step	Revenue	Active
304901104810302	G-52 W-NEXT-Demand Cost of Gas	Revenue	Active
304901114810302	G-52 W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124810302	G-52 W-NEXT-Reconciliation Costs	Revenue	Active
304901134810302	G-52 W-NEXT-Working Capital Allowance	Revenue	Active
304901144810302	G-52 W-NEXT-Bad Debt Allowance	Revenue	Active
304901154810302	G-52 W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164810302	G-52 W-NEXT-Production & Storage Capacity	Revenue	Active
304901174810302	G-52 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404810302	G-52 S-NEXT-Demand Cost of Gas	Revenue	Active
304901414810302	G-52 S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424810302	G-52 S-NEXT-Reconciliation Costs	Revenue	Active
304901434810302	G-52 S-NEXT-Working Capital Allowance	Revenue	Active
304901444810302	G-52 S-NEXT-Bad Debt Allowance	Revenue	Active
304901454810302	G-52 S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464810302	G-52 S-NEXT-Production & Storage Capacity	Revenue	Active
304901474810302	G-52 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704810302	G-52 NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714810302	G-52 NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
304901724810302	G-52 S-NEXT-DSM (Demand Side Management)	Revenue	Active
304901734810302	G-52 S-NEXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744810302	G-52 S-NEXT-ITM (Interruptible Margins)	Revenue	Active
304901754810302	G-52 S-NEXT-Wells LNG	Revenue	Active
304901764810302	G-52 S-NEXT-CCE (Customer Choice Expense)	Revenue	Active

Account Code	Description	Type	Status
304901774810302	G-52 S-NEXT-RLIAP (Residential Low Income)	Revenue	Active
304901784810302	G-52 S-NEXT-RCE (Rate Case Expense)	Revenue	Active
304901794810302	G-52 S-NEXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004810302	G52- NU Converted Revenue	Revenue	Active
305008014810302	G-52-W-NEXT Customer Charge	Revenue	Active
305008024810302	G-52-W-NEXT First Step	Revenue	Active
305008034810302	G-52-W-NEXT Excess	Revenue	Active
305008064810302	G-52-S-NEXT Customer Charge	Revenue	Active
305008074810302	G-52-S-NEXT First Step	Revenue	Active
305008084810302	G-52-S-NEXT Excess	Revenue	Active
305901104810302	G-52-W-NEXT Demand COG	Revenue	Active
305901114810302	G-52-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124810302	G-52-W-NEXT LPG & LNG Storage	Revenue	Active
305901134810302	G-52-W-NEXT Working Capital Commodity	Revenue	Active
305901144810302	G-52-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154810302	G-52-W-NEXT Commodity COG	Revenue	Active
305901164810302	G-52-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174810302	G-52-W-NEXT Working Capital Demand	Revenue	Active
305901184810302	G-52-W-NEXT Bad Debt	Revenue	Active
305901404810302	G-52-S-NEXT Demand COG	Revenue	Active
305901414810302	G-52-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424810302	G-52-S-NEXT LPG & LNG Storage	Revenue	Active
305901434810302	G-52-S-NEXT Working Capital Commodity	Revenue	Active
305901444810302	G-52-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454810302	G-52-S-NEXT Commodity COG	Revenue	Active
305901464810302	G-52-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474810302	G-52-S-NEXT Working Capital Demand	Revenue	Active
305901484810302	G-52-S-NEXT Bad Debt	Revenue	Active
305901704810302	G-52-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714810302	G-52-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724810302	G-52-S-NEXT Wells Surcharge	Revenue	Active
305901734810302	G-52-S-NEXT EERA	Revenue	Active
305901744810302	G-52-S-NEXT ERC	Revenue	Active
304008004810400	REV-INTERRUPTIBLE	Revenue	Active
304008904810400	IG Interrubtible Transport - Non Ext Sup	Revenue	Active
304008914810400	IG Interrubtible Supply	Revenue	Active
304901904810400	IG Interruptible Transport - Non Ext Sup	Revenue	Active
304901914810400	IG Interruptible Supply	Revenue	Active
305008004810400	REV-INTERRUPTIBLE	Revenue	Active
305008904810400	IG Interrubtible Transport - Non Ext Sup	Revenue	Active
305008914810400	IG INTERRUPTIBLE SUPPLY	Revenue	Active
305901904810400	IG Interruptible Transport - Non Ext Sup	Revenue	Active
305901914810400	IG Interruptible Supply	Revenue	Active
304008004811001	SIMPLEX NU CONVERTED REVENUE	Revenue	Active
304008014811001	Simplex W-NEXT-Customer Charge	Revenue	Active
304008024811001	Simplex W-NEXT-First Step	Revenue	Active
304008064811001	Simplex S-NEXT-Customer Charge	Revenue	Active
304008074811001	Simplex S-NEXT-First Step	Revenue	Active
304901104811001	Simplex W-NEXT-Demand Cost of Gas	Revenue	Active
304901114811001	Simplex W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124811001	Simplex W-NEXT-Reconciliation Costs	Revenue	Active
304901134811001	Simplex W-NEXT-Working Capital Allowance	Revenue	Active
304901144811001	Simplex W-NEXT-Bad Debt Allowance	Revenue	Active
304901154811001	Simplex W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164811001	Simplex W-NEXT-Production & Storage Capacity	Revenue	Active
304901174811001	Simplex W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404811001	Simplex S-NEXT-Demand Cost of Gas	Revenue	Active
304901414811001	Simplex S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424811001	Simplex S-NEXT-Reconciliation Costs	Revenue	Active
304901434811001	Simplex S-NEXT-Working Capital Allowance	Revenue	Active
304901444811001	Simplex S-NEXT-Bad Debt Allowance	Revenue	Active
304901454811001	Simplex S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464811001	Simplex S-NEXT-Production & Storage Capacity	Revenue	Active
304901474811001	SIMPLEX S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active

Account Code	Description	Type	Status
304901704811001	SIMPLEX NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714811001	SIMPLEX NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
305008004811001	JJ NISSEN NU CONVERTED REVENUE	Revenue	Active
305008014811001	JJ Nissen-W-NEXT Customer Charge	Revenue	Active
305008024811001	JJ Nissen-W-NEXT First Step	Revenue	Active
305008064811001	JJ Nissen-S-NEXT Customer Charge	Revenue	Active
305008074811001	JJ Nissen-S-NEXT First Step	Revenue	Active
305901104811001	JJ Nissen-W-NEXT Demand COG	Revenue	Active
305901114811001	JJ Nissen-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124811001	JJ Nissen-W-NEXT LPG & LNG Storage	Revenue	Active
305901134811001	JJ Nissen-W-NEXT Working Capital Commodity	Revenue	Active
305901144811001	JJ Nissen-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154811001	JJ Nissen-W-NEXT Commodity COG	Revenue	Active
305901164811001	JJ Nissen-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174811001	JJ Nissen-W-NEXT Working Capital Demand	Revenue	Active
305901184811001	JJ Nissen-W-NEXT Bad Debt	Revenue	Active
305901404811001	JJ Nissen-S-NEXT Demand COG	Revenue	Active
305901414811001	JJ Nissen-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424811001	JJ Nissen-S-NEXT LPG & LNG Storage	Revenue	Active
305901434811001	JJ Nissen-S-NEXT Working Capital Commodity	Revenue	Active
305901444811001	JJ Nissen-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454811001	JJ Nissen-S-NEXT Commodity COG	Revenue	Active
305901464811001	JJ Nissen-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474811001	JJ Nissen-S-NEXT Working Capital Demand	Revenue	Active
305901484811001	JJ Nissen-S-NEXT Bad Debt	Revenue	Active
305901704811001	JJ NISSEN-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714811001	JJ NISSEN-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724811001	JJ Nissen-S-NEXT Wells Surcharge	Revenue	Active
305901734811001	JJ Nissen-S-NEXT EERA	Revenue	Active
305901744811001	JJ Nissen-S-NEXT ERC	Revenue	Active
304008004811101	NAT GYPSUM NU CONVERTED REVENUE	Revenue	Active
304008014811101	Nat Gypsum W-NEXT-Customer Charge	Revenue	Active
304008024811101	Nat Gypsum W-NEXT-First Step	Revenue	Active
304008064811101	Nat Gypsum S-NEXT-Customer Charge	Revenue	Active
304008074811101	Nat Gypsum S-NEXT-First Step	Revenue	Active
304901104811101	Nat Gypsum W-NEXT-Demand Cost of Gas	Revenue	Active
304901114811101	Nat Gypsum W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124811101	Nat Gypsum W-NEXT-Reconciliation Costs	Revenue	Active
304901134811101	Nat Gypsum W-NEXT-Working Capital Allowance	Revenue	Active
304901144811101	Nat Gypsum W-NEXT-Bad Debt Allowance	Revenue	Active
304901154811101	Nat Gypsum W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164811101	Nat Gypsum W-NEXT-Production & Storage Capacity	Revenue	Active
304901174811101	Nat Gypsum W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404811101	Nat Gypsum S-NEXT-Demand Cost of Gas	Revenue	Active
304901414811101	Nat Gypsum S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424811101	Nat Gypsum S-NEXT-Reconciliation Costs	Revenue	Active
304901434811101	Nat Gypsum S-NEXT-Working Capital Allowance	Revenue	Active
304901444811101	Nat Gypsum S-NEXT-Bad Debt Allowance	Revenue	Active
304901454811101	Nat Gypsum S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464811101	Nat Gypsum S-NEXT-Production & Storage Capacity	Revenue	Active
304901474811101	NAT GYPSUM S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704811101	NAT GYPSUM NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714811101	NAT GYPSUM NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
305008004811101	NAVEL SHIPYARD NU CONVERTED REVENUE	Revenue	Active
305008014811101	Naval Shipyard-W-NEXT Customer Charge	Revenue	Active
305008024811101	Naval Shipyard-W-NEXT First Step	Revenue	Active
305008034811101	Naval Shipyard-W-NEXT Excess	Revenue	Active
305008064811101	Naval Shipyard-S-NEXT Customer Charge	Revenue	Active
305008074811101	Naval Shipyard-S-NEXT First Step	Revenue	Active
305008084811101	Naval Shipyard-S-NEXT Excess	Revenue	Active
305901104811101	Naval Shipyard-W-NEXT Demand COG	Revenue	Active
305901114811101	Naval Shipyard-W-NEXT Non Core Margins - 90%	Revenue	Active
305901124811101	Naval Shipyard-W-NEXT LPG & LNG Storage	Revenue	Active
305901134811101	Naval Shipyard-W-NEXT Working Capital Commodity	Revenue	Active

Account Code	Description	Type	Status
305901144811101	Naval Shipyard-W-NEXT Prior Over/Under Demand	Revenue	Active
305901154811101	Naval Shipyard-W-NEXT Commodity COG	Revenue	Active
305901164811101	Naval Shipyard-W-NEXT Prior Over/Under Commodity	Revenue	Active
305901174811101	Naval Shipyard-W-NEXT Working Capital Demand	Revenue	Active
305901184811101	Naval Shipyard-W-NEXT Bad Debt	Revenue	Active
305901404811101	Naval Shipyard-S-NEXT Demand COG	Revenue	Active
305901414811101	Naval Shipyard-S-NEXT Non Core Margins - 90%	Revenue	Active
305901424811101	Naval Shipyard-S-NEXT LPG & LNG Storage	Revenue	Active
305901434811101	Naval Shipyard-S-NEXT Working Capital Commodity	Revenue	Active
305901444811101	Naval Shipyard-S-NEXT Prior Over/Under Demand	Revenue	Active
305901454811101	Naval Shipyard-S-NEXT Commodity COG	Revenue	Active
305901464811101	Naval Shipyard-S-NEXT Prior Over/Under Commodity	Revenue	Active
305901474811101	Naval Shipyard-S-NEXT Working Capital Demand	Revenue	Active
305901484811101	Naval Shipyard-S-NEXT Bad Debt	Revenue	Active
305901704811101	NAVAL SHIPYARD-NEXT SUPPLIER REFUND DEMAND	Revenue	Active
305901714811101	NAVAL SHIPYARD-NEXT SUPPLIER REFUND COMMODITY	Revenue	Active
305901724811101	Naval Shipyard-S-NEXT Wells Surcharge	Revenue	Active
305901734811101	Naval Shipyard-S-NEXT EERA	Revenue	Active
305901744811101	Naval Shipyard-S-NEXT ERC	Revenue	Active
304008004811201	FOSS NU CONVERTED REVENUE	Revenue	Active
304008014811201	Foss W-NEXT-Customer Charge	Revenue	Active
304008024811201	Foss W-NEXT-First Step	Revenue	Active
304008034811201	Foss W-NEXT-Excess	Revenue	Active
304008044811201	Foss W-NEXT-Excess (2)	Revenue	Active
304008054811201	Foss S-NEXT-Excess (3)	Revenue	Active
304008064811201	Foss S-NEXT-Customer Charge	Revenue	Active
304008074811201	Foss S-NEXT-First Step	Revenue	Active
304008084811201	Foss S-NEXT-Excess	Revenue	Active
304008094811201	Foss S-NEXT-Excess (2)	Revenue	Active
304901104811201	Foss W-NEXT-Demand Cost of Gas	Revenue	Active
304901114811201	Foss W-NEXT-Commodity Cost of Gas	Revenue	Active
304901124811201	Foss W-NEXT-Reconciliation Costs	Revenue	Active
304901134811201	Foss W-NEXT-Working Capital Allowance	Revenue	Active
304901144811201	Foss W-NEXT-Bad Debt Allowance	Revenue	Active
304901154811201	Foss W-NEXT-Miscellaneous Overhead	Revenue	Active
304901164811201	Foss W-NEXT-Production & Storage Capacity	Revenue	Active
304901174811201	Foss W-NEXT-Deferral of Jurisdictional Demand Costs	Revenue	Active
304901404811201	Foss S-NEXT-Demand Cost of Gas	Revenue	Active
304901414811201	Foss S-NEXT-Commodity Cost of Gas	Revenue	Active
304901424811201	Foss S-NEXT-Reconciliation Costs	Revenue	Active
304901434811201	Foss S-NEXT-Working Capital Allowance	Revenue	Active
304901444811201	Foss S-NEXT-Bad Debt Allowance	Revenue	Active
304901454811201	Foss S-NEXT-Miscellaneous Overhead	Revenue	Active
304901464811201	Foss S-NEXT-Production & Storage Capacity	Revenue	Active
304901474811201	FOSS S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenue	Active
304901704811201	FOSS NEXT-SUPPLIER REFUNDS (DEMAND)	Revenue	Active
304901714811201	FOSS NEXT-SUPPLIER REFUNDS (COMMODITY)	Revenue	Active
300013104830000	SALES FOR RESALE - DEMAND - PEAK - COMMON	Revenue	Active
300013404830000	SALES FOR RESALE - DEMAND - OFF PEAK - COMMON	Revenue	Active
304913104830000	SALES FOR RESALE - DEMAND - PEAK - NH	Revenue	Active
305913104830000	SALES FOR RESALE - DEMAND - PEAK - ME	Revenue	Active
300013104830001	SALES FOR RESALE - COMMODITY - PEAK - COMMON	Revenue	Active
304913114830001	SALES FOR RESALE - COMMODITY - PEAK - NH	Revenue	Active
304913414830001	SALES FOR RESALE - COMMODITY - OFF PEAK - NH	Revenue	Active
305913154830001	SALES FOR RESALE - COMMODITY - PEAK - ME	Revenue	Active
305913454830001	SALES FOR RESALE - COMMODITY - OFF PEAK - ME	Revenue	Active
300013104830100	SUPPLIER CREDIT - DEMAND - PEAK - COMMON	Revenue	Active
300013404830100	SUPPLIER CREDIT - DEMAND - OFF PEAK - COMMON	Revenue	Active
304913104830100	SUPPLIER CREDIT - DEMAND - PEAK - NH	Revenue	Active
305913104830100	SUPPLIER CREDIT - DEMAND - PEAK - ME	Revenue	Active
300013104830101	SUPPLIER CREDIT - COMMODITY - PEAK - COMMON	Revenue	Active
305913154830101	SUPPLIER CREDIT - COMMODITY - PEAK - ME	Revenue	Active
305913454830101	SUPPLIER CREDIT - COMMODITY - OFF PEAK - ME	Revenue	Active
304913104830200	PIPELINE COMPANY MANAGED DEMAND - PEAK - NH	Revenue	Active

Account Code	Description	Type	Status
304913114830200	PIPELINE COMPANY MANAGED COMMODITY- PEAK - NH	Revenue	Active
304913414830200	PIPELINE COMPANY MANAGED COMMODITY- OFF PEAK - NH	Revenue	Active
305913104830200	COMPANY MANAGED PEAK-ME	Revenue	Active
305913154830200	COMPANY MANAGED COMMODITY PEAK-ME	Revenue	Active
304913104830300	STORAGE COMPANY MANAGED DEMAND - PEAK - NH	Revenue	Active
304913114830300	STORAGE COMPANY MANAGED COMMODITY- PEAK - NH	Revenue	Active
304913104830400	PEAKING COMPANY MANAGED DEMAND - PEAK - NH	Revenue	Active
304913114830400	PEAKING COMPANY MANAGED COMMODITY- PEAK - NH	Revenue	Active
304913114831090	SALES FOR RESALE - COMMODITY - PEAK - NH - ESTIMATE	Revenue	Active
304913414831090	SALES FOR RESALE-COM- OP-NH -EST	Revenue	Active
305913154831090	SALES FOR RESALE - COMMODITY - PEAK - ME - ESTIMATE	Revenue	Active
305913454831090	SALES FOR RESALE-COM-OP- ME-EST	Revenue	Active
304913104832090	PIPELINE COMPANY MANAGED DEMAND - PEAK - NH EST	Revenue	Active
304913114832090	PIPELINE COMPANY MANAGED COMMODITY- PEAK - NH EST	Revenue	Active
304913414832090	PIPELINE COMPANY MANAGED COMMODITY- OFF PEAK - NH EST	Revenue	Active
305913104832090	COMPANY MANAGED - DEMAND -PEAK-ME EST	Revenue	Active
305913154832090	COMPANY MANAGED COMMODITY PEAK-ME EST	Revenue	Active
304913104833090	STORAGE COMPANY MANAGED DEMAND - PEAK - NH EST	Revenue	Active
304913114833090	STORAGE COMPANY MANAGED COMMODITY- PEAK - NH EST	Revenue	Active
304913414833090	STORAGE COMPANY MANAGED COMMODITY- OFF PEAK - NH EST	Revenue	Active
304913104834090	PEAKING COMPANY MANAGED DEMAND - PEAK - NH EST	Revenue	Active
304913114834090	PEAKING COMPANY MANAGED COMMODITY- PEAK - NH EST	Revenue	Active
304913414834090	PEAKING COMPANY MANAGED COMMODITY- OFF PEAK - NH EST	Revenue	Active
304913114840000	TRANSPORTATION CHARGES - COMMODITY - PEAK - NH	Revenue	Active
304913414840000	TRANSPORTATION CHARGES - COMMODITY - OFF PEAK - NH	Revenue	Active
305913154840000	TRANSPORTATION CHARGES - COMMODITY - PEAK - ME	Revenue	Active
305913454840000	TRANSPORTATION CHARGES - COMMODITY - OFF PEAK - ME	Revenue	Active
304913104840100	STANDBY & FIRM DELIVERY SERVICE PEAK - NH	Revenue	Active
305913104840100	STANDBY & FIRM DELIVERY SERVICE - PEAK - ME	Revenue	Active
304008004841000	UNCHARGED COMMERCIAL TRANSPORTATION	Revenue	Active
305008004841000	UNCHARGED COMMERCIAL TRANSPORTATION	Revenue	Active
304008004841100	UNCHARGED INDUSTRIAL TRANSPORTATION	Revenue	Active
305008004841100	UNCHARGED INDUSTRIAL TRANSPORTATION	Revenue	Active
304008004850000	UNBILLED SALE	Revenue	Active
304010004850000	UNBILLED SALES	Revenue	Active
305008004850000	UNBILLED SALE	Revenue	Active
305010004850000	UNBILLED SALES	Revenue	Active
304010004852100	COMMERCIAL TRANS NORMALIZATION	Revenue	Active
305010004852100	COMMERCIAL TRANS NORMALIZATION	Revenue	Active
304010004855200	INDUSTRIAL TRANS NORMALIZATION	Revenue	Active
305010004855200	INDUSTRIAL TRANS NORMALIZATION	Revenue	Active
304008004860000	RESIDENTIAL DISCOUNT-NET REV	Revenue	Active
304008004870000	OTH REV-LATE/PMT CHG/RET CHK	Revenue	Active
305008004870000	OTH REV-LATE/PMT CHG/RET CHK	Revenue	Active
304008004870001	LATE PAYMENT FEE - RES - NH	Revenue	Active
305008004870001	LATE PAYMENT FEE - RES - ME	Revenue	Active
304008004870002	LATE PAYMENT FEE - COMM - NH	Revenue	Active
305008004870002	LATE PAYMENT FEE - COMM - ME	Revenue	Active
304008004870003	LATE PAYMENT FEE - ANCILLARY SERVICES	Revenue	Active
305008004870003	LATE PAYMENT FEE - ANCILLARY SERVICES	Revenue	Active
304008004880000	RENTAL REVENUE	Revenue	Active
304729604880000	EQUIP PROTECTION PLAN REVENUE - COMMERCIAL	Revenue	Active
305008004880000	RENTAL REVENUE	Revenue	Active
305802524880000	CONVERSION BURNER RENTAL REVENUE-GAS	Revenue	Active
304008004880003	RECONNECT FEE - NH	Revenue	Active
305008004880003	RECONNECT FEE - ME	Revenue	Active
304008004880004	UNAUTHORIZED USE OF GAS - NH	Revenue	Active
305008004880004	UNAUTHORIZED USE OF GAS - ME	Revenue	Active
304008004880005	POOL ADMINISTRATION	Revenue	Active
304008004880006	3RD PARTY BILLING	Revenue	Active
304008004880007	CUSTOMER TELEMETERING	Revenue	Active
305008004880007	CUSTOMER TELEMETERING	Revenue	Active
304008004880008	METER TEST REVENUE	Revenue	Active
305008004880008	METER TEST REVENUE	Revenue	Active

Account Code	Description	Type	Status
304008004880009	CUSTOMER RE-ENTRY FEE	Revenue	Active
305008004880009	CUSTOMER RE-ENTRY FEE	Revenue	Active
304729504880100	WATER HEATER RENTAL-REVENUE	Revenue	Active
304729514880100	CLEAN & CHECK REVENUE	Revenue	Active
304729524880100	CONVERSION BURNER RENTAL-REVENUE	Revenue	Active
304729534880100	EASY CARE SVC PLAN REVENUE	Revenue	Active
304729544880100	INTERIOR GAS LINES REV- RESIDENTIAL	Revenue	Active
304729554880100	ANNUAL INSPECTION REVENUE - NH	Revenue	Active
304729534880200	EQUIP PROTECTION PLAN REVENUE	Revenue	Active
304729504880500	RENTAL WH BAD DEBT - NH	Revenue	Active
304729524880500	CONV BURN BAD DEBT - NH	Revenue	Active
304080004882000	UNH REVENUE- NH	Revenue	Active
304008004890000	BUNDLED REVENUE NU & EUSA	Revenue	Active
305008004890000	BUNDLED REVENUE NU & EUSA	Revenue	Active
304008004890101	R-6 NU CONVERTED REVENUE	Revenue	Active
304008014890101	R-6 W-EXT-Customer Charge	Revenue	Active
304008024890101	R-6 W-EXT-First Step	Revenue	Active
304008034890101	R-6 W-EXT-Excess	Revenue	Active
304008064890101	R-6 S-EXT-Customer Charge	Revenue	Active
304008074890101	R-6 S-EXT-First Step	Revenue	Active
304008084890101	R-6 S-EXT-Excess	Revenue	Active
304901204890101	R-6 EXT-Capacity Reserve Charge	Revenue	Active
304901724890101	R-6 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734890101	R-6 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890101	R-6 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890101	R-6 S-EXT-Wells LNG	Revenue	Active
304901774890101	R-6 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890101	R-6 EXT-RCE	Revenue	Active
304901794890101	R-6 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890101	R-1 NU CONVERTED REVENUE	Revenue	Active
305008014890101	R-1-W-EXT Customer Charge	Revenue	Active
305008024890101	R-1-W-EXT First Step	Revenue	Active
305008034890101	R-1-W-EXT Excess	Revenue	Active
305008064890101	R-1-S-EXT Customer Charge	Revenue	Active
305008074890101	R-1-S-EXT First Step	Revenue	Active
305008084890101	R-1-S-EXT Excess	Revenue	Active
305901194890101	R-1-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890101	R-1-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890101	R-1-S-EXT EERA	Revenue	Active
305901744890101	R-1-S-EXT ERC	Revenue	Active
305901764890101	R1 LOW INCOME CREDIT DISCOUNT	Revenue	Active
304008004890102	R-11 NU CONVERTED REVENUE	Revenue	Active
304008014890102	R-11 W-EXT-Customer Charge	Revenue	Active
304008024890102	R-11 W-EXT-First Step	Revenue	Active
304008034890102	R-11 W-EXT-Excess	Revenue	Active
304008064890102	R-11 S-EXT-Customer Charge	Revenue	Active
304008074890102	R-11 S-EXT-First Step	Revenue	Active
304008084890102	R-11 S-EXT-Excess	Revenue	Active
304901204890102	R-11 EXT-Capacity Reserve Charge	Revenue	Active
304901724890102	R-11 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734890102	R-11 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890102	R-11 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890102	R-11 S-EXT-Wells LNG	Revenue	Active
304901774890102	R-11 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890102	R-11 EXT-RCE	Revenue	Active
304901794890102	R-11 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
304008004890103	R-5 NU CONVERTED REVENUE	Revenue	Active
304008014890103	R-5 W-EXT-Customer Charge	Revenue	Active
304008024890103	R-5 W-EXT-First Step	Revenue	Active
304008034890103	R-5 W-EXT-Excess	Revenue	Active
304008064890103	R-5 S-EXT-Customer Charge	Revenue	Active
304008074890103	R-5 S-EXT-First Step	Revenue	Active
304008084890103	R-5 S-EXT-Excess	Revenue	Active
304901204890103	R-5 EXT-Capacity Reserve Charge	Revenue	Active

Account Code	Description	Type	Status
304901724890103	R-5 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734890103	R-5 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890103	R-5 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890103	R-5 S-EXT-Wells LNG	Revenue	Active
304901774890103	R-5 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890103	R-5 EXT-RCE	Revenue	Active
304901794890103	R-5 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890103	R-2 NU CONVERTED REVENUE	Revenue	Active
305008014890103	R-2-W-EXT Customer Charge	Revenue	Active
305008024890103	R-2-W-EXT First Step	Revenue	Active
305008034890103	R-2-W-EXT Excess	Revenue	Active
305008064890103	R-2-S-EXT Customer Charge	Revenue	Active
305008074890103	R-2-S-EXT First Step	Revenue	Active
305008084890103	R-2-S-EXT Excess	Revenue	Active
305901194890103	R-2-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890103	R-2-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890103	R-2-S-EXT EERA	Revenue	Active
305901744890103	R-2-S-EXT ERC	Revenue	Active
305901764890103	R2 LOW INCOME CREDIT DISCOUNT	Revenue	Active
304008004890104	R-10 NU CONVERTED REVENUE	Revenue	Active
304008014890104	R-10 W-EXT-Customer Charge	Revenue	Active
304008024890104	R-10 W-EXT-First Step	Revenue	Active
304008034890104	R-10 W-EXT-Excess	Revenue	Active
304008064890104	R-10 S-EXT-Customer Charge	Revenue	Active
304008074890104	R-10 S-EXT-First Step	Revenue	Active
304008084890104	R-10 S-EXT-Excess	Revenue	Active
304901204890104	R-10 EXT-Capacity Reserve Charge	Revenue	Active
304901724890104	R-10 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734890104	R-10 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890104	R-10 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890104	R-10 S-EXT-Wells LNG	Revenue	Active
304901774890104	R-10 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890104	R-10 EXT-RCE	Revenue	Active
304901794890104	R-10 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
304008004890201	TP40-LOW ANNUAL USE	Revenue	Active
304008014890201	G-40 W-EXT-Customer Charge	Revenue	Active
304008024890201	G-40 W-EXT-First Step	Revenue	Active
304008034890201	G-40 W-EXT-Excess	Revenue	Active
304008064890201	G-40 S-EXT-Customer Charge	Revenue	Active
304008074890201	G-40 S-EXT-First Step	Revenue	Active
304008084890201	G-40 S-EXT-Excess	Revenue	Active
304901204890201	G-40 EXT-Capacity Reserve Charge	Revenue	Active
304901724890201	G-40 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734890201	G-40 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890201	G-40 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890201	G-40 S-EXT-Wells LNG	Revenue	Active
304901764890201	G-40 S-EXT-CCE (Customer Choice Expense)	Revenue	Active
304901774890201	G-40 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890201	G-40 EXT-RCE	Revenue	Active
304901794890201	G-40 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890201	T40-LOW ANNUAL USE	Revenue	Active
305008014890201	G-40-W-EXT Customer Charge	Revenue	Active
305008024890201	G-40-W-EXT First Step	Revenue	Active
305008034890201	G-40-W-EXT Excess	Revenue	Active
305008064890201	G-40-S-EXT Customer Charge	Revenue	Active
305008074890201	G-40-S-EXT First Step	Revenue	Active
305008084890201	G-40-S-EXT Excess	Revenue	Active
305901194890201	G-40-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890201	G-40-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890201	G-40-S-EXT EERA	Revenue	Active
305901744890201	G-40-S-EXT ERC	Revenue	Active
304008004890202	T50-LOW ANNUAL/LOW WINTER	Revenue	Active
304008014890202	G-50 W-EXT-Customer Charge	Revenue	Active
304008024890202	G-50 W-EXT-First Step	Revenue	Active

Account Code	Description	Type	Status
304008034890202	G-50 W-EXT-Excess	Revenue	Active
304008064890202	G-50 S-EXT-Customer Charge	Revenue	Active
304008074890202	G-50 S-EXT-First Step	Revenue	Active
304008084890202	G-50 S-EXT-Excess	Revenue	Active
304901204890202	G-50 EXT-Capacity Reserve Charge	Revenue	Active
304901724890202	G-50 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenue	Active
304901734890202	G-50 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890202	G-50 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890202	G-50 S-EXT-Wells LNG	Revenue	Active
304901764890202	G-50 S-EXT-CCE (Customer Choice Expense)	Revenue	Active
304901774890202	G-50 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890202	G-50 EXT-RCE	Revenue	Active
304901794890202	G-50 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890202	T50-LOW ANNUAL/LOW WINTER	Revenue	Active
305008014890202	G-50-W-EXT Customer Charge	Revenue	Active
305008024890202	G-50-W-EXT First Step	Revenue	Active
305008034890202	G-50-W-EXT Excess	Revenue	Active
305008064890202	G-50-S-EXT Customer Charge	Revenue	Active
305008074890202	G-50-S-EXT First Step	Revenue	Active
305008084890202	G-50-S-EXT Excess	Revenue	Active
305901194890202	G-50-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890202	G-50-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890202	G-50-S-EXT EERA	Revenue	Active
305901744890202	G-50-S-EXT ERC	Revenue	Active
304008004890301	T41-MED ANNUAL/HIGH WINTER	Revenue	Active
304008014890301	G-41 W-EXT-Customer Charge	Revenue	Active
304008024890301	G-41 W-EXT-First Step	Revenue	Active
304008064890301	G-41 S-EXT-Customer Charge	Revenue	Active
304008074890301	G-41 S-EXT-First Step	Revenue	Active
304901204890301	G-41 EXT-Capacity Reserve Charge	Revenue	Active
304901724890301	G-41 S-EXT-DSM (Demand Side Management)	Revenue	Active
304901734890301	G-41 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890301	G-41 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890301	G-41 S-EXT-Wells LNG	Revenue	Active
304901764890301	G-41 S-EXT-CCE (Customer Choice Expense)	Revenue	Active
304901774890301	G-41 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890301	G-41 EXT-RCE	Revenue	Active
304901794890301	G-41 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890301	T41-MED ANNUAL/HIGH WINTER	Revenue	Active
305008014890301	G-41-W-EXT Customer Charge	Revenue	Active
305008024890301	G-41-W-EXT First Step	Revenue	Active
305008034890301	G-41-W-EXT Excess	Revenue	Active
305008064890301	G-41-S-EXT Customer Charge	Revenue	Active
305008074890301	G-41-S-EXT First Step	Revenue	Active
305008084890301	G-41-S-EXT Excess	Revenue	Active
305901194890301	G-41-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890301	G-41-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890301	G-41-S-EXT EERA	Revenue	Active
305901744890301	G-41-S-EXT ERC	Revenue	Active
304008004890302	T51-MED ANNUAL/LOW WINTER	Revenue	Active
304008014890302	G-51 W-EXT-Customer Charge	Revenue	Active
304008024890302	G-51 W-EXT-First Step	Revenue	Active
304008034890302	G-51 W-EXT-Excess	Revenue	Active
304008064890302	G-51 S-EXT-Customer Charge	Revenue	Active
304008074890302	G-51 S-EXT-First Step	Revenue	Active
304008084890302	G-51 S-EXT-Excess	Revenue	Active
304901204890302	G-51 EXT-Capacity Reserve Charge	Revenue	Active
304901724890302	G-51 S-EXT-DSM (Demand Side Management)	Revenue	Active
304901734890302	G-51 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890302	G-51 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890302	G-51 S-EXT-Wells LNG	Revenue	Active
304901764890302	G-51 S-EXT-CCE (Customer Choice Expense)	Revenue	Active
304901774890302	G-51 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890302	G-51 EXT-RCE	Revenue	Active

Account Code	Description	Type	Status
304901794890302	G-51 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890302	T51-MED ANNUAL/LOW WINTER	Revenue	Active
305008014890302	G-51-W-EXT Customer Charge	Revenue	Active
305008024890302	G-51-W-EXT First Step	Revenue	Active
305008034890302	G-51-W-EXT Excess	Revenue	Active
305008064890302	G-51-S-EXT Customer Charge	Revenue	Active
305008074890302	G-51-S-EXT First Step	Revenue	Active
305008084890302	G-51-S-EXT Excess	Revenue	Active
305901194890302	G-51-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890302	G-51-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890302	G-51-S-EXT EERA	Revenue	Active
305901744890302	G-51-S-EXT ERC	Revenue	Active
304008004890401	T42-HIGH ANNUAL/HIGH WINTER	Revenue	Active
304008014890401	G-42 W-EXT-Customer Charge	Revenue	Active
304008024890401	G-42 W-EXT-First Step	Revenue	Active
304008064890401	G-42 S-EXT-Customer Charge	Revenue	Active
304008074890401	G-42 S-EXT-First Step	Revenue	Active
304901204890401	G-42 EXT-Capacity Reserve Charge	Revenue	Active
304901724890401	G-42 S-EXT-DSM (Demand Side Management)	Revenue	Active
304901734890401	G-42 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890401	G-42 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890401	G-42 S-EXT-Wells LNG	Revenue	Active
304901764890401	G-42 S-EXT-CCE (Customer Choice Expense)	Revenue	Active
304901774890401	G-42 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890401	G-42 EXT-RCE	Revenue	Active
304901794890401	G-42 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890401	G-42-NU CONVERTED REVENUE	Revenue	Active
305008014890401	G-42-W-EXT Customer Charge	Revenue	Active
305008024890401	G-42-W-EXT First Step	Revenue	Active
305008034890401	G-42-W-EXT Excess	Revenue	Active
305008064890401	G-42-S-EXT Customer Charge	Revenue	Active
305008074890401	G-42-S-EXT First Step	Revenue	Active
305008084890401	G-42-S-EXT Excess	Revenue	Active
305901194890401	G-42-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890401	G-42-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890401	G-42-S-EXT EERA	Revenue	Active
305901744890401	G-42-S-EXT ERC	Revenue	Active
304008004890402	T52-HIGH ANNUAL/LOW WINTER	Revenue	Active
304008014890402	G-52 W-EXT-Customer Charge	Revenue	Active
304008024890402	G-52 W-EXT-First Step	Revenue	Active
304008064890402	G-52 S-EXT-Customer Charge	Revenue	Active
304008074890402	G-52 S-EXT-First Step	Revenue	Active
304901204890402	G-52 EXT-Capacity Reserve Charge	Revenue	Active
304901724890402	G-52 S-EXT-DSM (Demand Side Management)	Revenue	Active
304901734890402	G-52 S-EXT-ERC (Environmental Recovery Costs)	Revenue	Active
304901744890402	G-52 S-EXT-ITM (Interruptible Margins)	Revenue	Active
304901754890402	G-52 S-EXT-Wells LNG	Revenue	Active
304901764890402	G-52 S-EXT-CCE (Customer Choice Expense)	Revenue	Active
304901774890402	G-52 S-EXT-RLIAP (Residential Low Income)	Revenue	Active
304901784890402	G-52 EXT-RCE	Revenue	Active
304901794890402	G-52 S-EXT-RPC (Recon of Perm Changes)	Revenue	Active
305008004890402	G-52 NU CONVERTED REVENUE	Revenue	Active
305008014890402	G-52-W-EXT Customer Charge	Revenue	Active
305008024890402	G-52-W-EXT First Step	Revenue	Active
305008034890402	G-52-W-EXT Excess	Revenue	Active
305008064890402	G-52-S-EXT Customer Charge	Revenue	Active
305008074890402	G-52-S-EXT First Step	Revenue	Active
305008084890402	G-52-S-EXT Excess	Revenue	Active
305901194890402	G-52-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204890402	G-52-S-EXT Capacity Reserve Charge	Revenue	Active
305901734890402	G-52-S-EXT EERA	Revenue	Active
305901744890402	G-52-S-EXT ERC	Revenue	Active
304901904890500	IG Interruptible Transport - Ext Sup	Revenue	Active
305901904890500	IG INTERRUPTIBLE TRANSPORT - EXT SUP	Revenue	Active

Account Code	Description	Type	Status
304008004891001	SIMPLEX NU CONVERTED REVENUE	Revenue	Active
304008014891001	Simplex W-EXT-Customer Charge	Revenue	Active
304008024891001	Simplex W-EXT-First Step	Revenue	Active
304008064891001	Simplex S-EXT-Customer Charge	Revenue	Active
304008074891001	Simplex S-EXT-First Step	Revenue	Active
304901204891001	Simplex W-EXT-Cap Reserve	Revenue	Active
304901784891001	Simplex EXT-RCE	Revenue	Active
305008004891001	JJ NISSEN NU CONVERTED REVENUE	Revenue	Active
305008014891001	JJ Nissen-W-EXT Customer Charge	Revenue	Active
305008024891001	JJ Nissen-W-EXT First Step	Revenue	Active
305008064891001	JJ Nissen-S-EXT Customer Charge	Revenue	Active
305008074891001	JJ Nissen-S-EXT First Step	Revenue	Active
305901194891001	JJ Nissen-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204891001	JJ Nissen-S-EXT Capacity Reserve Charge	Revenue	Active
305901734891001	JJ Nissen-S-EXT EERA	Revenue	Active
305901744891001	JJ Nissen-S-EXT ERC	Revenue	Active
304008004891101	NAT GYPSUM NU CONVERTED REVENUE	Revenue	Active
304008014891101	Nat Gypsum W-EXT-Customer Charge	Revenue	Active
304008024891101	Nat Gypsum W-EXT-First Step	Revenue	Active
304008064891101	Nat Gypsum S-EXT-Customer Charge	Revenue	Active
304008074891101	Nat Gypsum S-EXT-First Step	Revenue	Active
304901204891101	Nat Gypsum EXT-Capacity Reserve Charge	Revenue	Active
304901784891101	Nat Gypsum EXT-RCE	Revenue	Active
305008004891101	NAVEL SHIPYARD NU CONVERTED REVENUE	Revenue	Active
305008014891101	Naval Shipyard-W-EXT Customer Charge	Revenue	Active
305008024891101	Naval Shipyard-W-EXT First Step	Revenue	Active
305008034891101	Naval Shipyard-W-EXT Excess	Revenue	Active
305008064891101	Naval Shipyard-S-EXT Customer Charge	Revenue	Active
305008074891101	Naval Shipyard-S-EXT First Step	Revenue	Active
305008084891101	Naval Shipyard-S-EXT Excess	Revenue	Active
305901194891101	Naval Shipyard-S-EXT Stipulation Demand Charge (SDC)	Revenue	Active
305901204891101	Naval Shipyard-S-EXT Capacity Reserve Charge	Revenue	Active
305901734891101	Naval Shipyard-S-EXT EERA	Revenue	Active
305901744891101	Naval Shipyard-S-EXT ERC	Revenue	Active
304008004891200	FOSS NU CONVERTED REVENUE	Revenue	Active
304008004891201	Foss W-EXT-Excess (3)	Revenue	Active
304008014891201	Foss W-EXT-Customer Charge	Revenue	Active
304008024891201	Foss W-EXT-First Step	Revenue	Active
304008034891201	Foss W-EXT-Excess	Revenue	Active
304008044891201	Foss W-EXT-Excess (2)	Revenue	Active
304008054891201	Foss S-EXT-Excess (3)	Revenue	Active
304008064891201	Foss S-EXT-Customer Charge	Revenue	Active
304008074891201	Foss S-EXT-First Step	Revenue	Active
304008084891201	Foss S-EXT-Excess	Revenue	Active
304008094891201	Foss S-EXT-Excess (2)	Revenue	Active
304901204891201	Foss EXT-Capacity Reserve Charge	Revenue	Active
304901784891201	Foss EXT-RCE	Revenue	Active
304008004930000	I/C RENT	Revenue	Active
304010004930000	INTERCOMPANY RENT	Revenue	Active
305008004930000	I/C RENT	Revenue	Active
305010004930000	INTERCOMPANY RENT	Revenue	Active
304010004950000	ACCRUED REVENUE - CYCLE 22 - NH	Revenue	Active
304080004950000	BUNDLED SERVICE EXP, OFF SYTEM SALES, SPECIAL DEALS	Revenue	Active
304901104950000	PEAK DEMAND ACCRUED REV - NH	Revenue	Active
304901134950000	PEAK WORK CAPITAL ACCRUED REV - NH	Revenue	Active
304901144950000	PEAK BAD DEBT ACCRUED REV - NH	Revenue	Active
304901404950000	OFF PEAK DEMAND ACCRUED REV - NH	Revenue	Active
304901434950000	OFF PEAK WORK CAPITAL ACCRUED REV - NH	Revenue	Active
304901444950000	OFF PEAK BAD DEBT ACCRUED REV - NH	Revenue	Active
304901704950000	ACCR REV-SUP REF-DEMAND-NH	Revenue	Active
304901774950000	ACCRUED REVENUE - LIEAP - NH	Revenue	Active
304910414950000	ACCRUED REV-DEMAND AND COMMODITY OFF PEAK	Revenue	Active
304910434950000	ACCRUED REV-WORKING CAPITAL OFF PEAK	Revenue	Active
304910444950000	ACCRUED REV-BAD DEBT OFF PEAK	Revenue	Active

Account Code	Description	Type	Status
305002734950000	ENERGY EFFICIENCY BILLED REVENUE	Revenue	Active
305010004950000	ACCRUED REVENUE - CYCLE 22 - ME	Revenue	Active
305085004950000	BUNDLED SERVICE EXP, OFF SYTEM SALES, SPECIAL DEALS	Revenue	Active
305901104950000	PEAK DEMAND ACCRUED REV - ME	Revenue	Active
305901134950000	PEAK COMMODITY WORK CAPITAL ACCRUED REV - ME	Revenue	Active
305901154950000	PEAK COMMODITY ACCRUED REV - ME	Revenue	Active
305901174950000	PEAK DEMAND WORK CAPITAL ACCRUED REV - ME	Revenue	Active
305901184950000	PEAK BAD DEBT ACCRUED REV - ME	Revenue	Active
305901404950000	OFF PEAK DEMAND ACCRUED REV - ME	Revenue	Active
305901434950000	OFF PEAK COMMODITY WORK CAPITAL ACCRUED REV - ME	Revenue	Active
305901454950000	OFF PEAK COMMODITY ACCRUED REV - ME	Revenue	Active
305901474950000	OFF PEAK DEMAND WORK CAPITAL ACCRUED REV - ME	Revenue	Active
305901484950000	OFF PEAK BAD DEBT ACCRUED REV - ME	Revenue	Active
305901704950000	ACCR REV-SUP REF-DEMAND-ME	Revenue	Active
305901714950000	ACCR REV-SUP REF-COMMOD-ME	Revenue	Active
305901764950000	NU ME ACCRUED REVENUE ME LOW INCOME	Revenue	Active
305010734950001	EE ACCRUED REVENUE	Revenue	Active
304010004950027	ACCRUED REVENUE - NON DIST BAD DEBT	Revenue	Active
305010004950027	ACCRUED REVENUE - NON DIST BAD DEBT	Revenue	Active
304910114950090	ACCRUED REVENUE-DEM_COMM- UNBILLED-PEAK	Revenue	Active
304910134950090	ACCRUED REVENUE-WORKING CAPITAL-UNBILLED- PEAK	Revenue	Active
304910144950090	ACCRUED REVENUE-BAD DEBT- UNBILLED- PEAK	Revenue	Active
304910414950090	ACCRUED REVENUE-DEM_COMM- UNBILLED-OFF PEAK	Revenue	Active
304910434950090	ACCRUED REVENUE-WORKING CAPITAL-UNBILLED- OFF PEAK	Revenue	Active
304910444950090	ACCRUED REVENUE-BAD DEBT- UNBILLED- PEAK	Revenue	Active
305910104950090	ACCRUED REV - UNBILLED-DEMAND-P-ME	Revenue	Active
305910134950090	ACCRUED REV - UNBILLED-WC-COMM-P-ME	Revenue	Active
305910154950090	ACCRUED REV - UNBILLED-COMM-P-ME	Revenue	Active
305910174950090	ACCRUED REV - UNBILLED-WC-DEMAND-P-ME	Revenue	Active
305910184950090	ACCRUED REV - UNBILLED-BAD DEBT-P-ME	Revenue	Active
305910404950090	ACCRUED REVENUE - UNBILLED-DEMAND-OP-ME	Revenue	Active
305910434950090	ACCRUED REV - UNBILLED-WC-COMM-OP-ME	Revenue	Active
305910454950090	ACCRUED REVENUE - UNBILLED-COMM-OP-ME	Revenue	Active
305910474950090	ACCRUED REV - UNBILLED-WC-DEMAND-OP-ME	Revenue	Active
305910484950090	ACCRUED REV - UNBILLED-BAD DEBT-OP-ME	Revenue	Active
304001724950099	LDAC-EEC LOST BASE REVENUE	Revenue	Active
304901724950099	LDAC-EEC LOST BASE REVENUE	Revenue	Active
305001734950099	EERA - ME - LOST BASE REVENUE	Revenue	Active
305901734950099	EERA - ME - LOST BASE REVENUE	Revenue	Active
304901734950100	REVENUE - LDAC-ERC-NH	Revenue	Active
305901744950100	REVENUE - LDAC - ERC - ME	Revenue	Active
304901724950101	ACCRUED REVENUE-LDAC-EEC-LOW INCOME	Revenue	Active
305901734950101	ACCRUED REVENUE - EERA - ME -Low Income	Revenue	Active
304901724950102	ACCRUED REVENUE-LDAC-EEC-RESIDENTIAL	Revenue	Active
305901734950102	ACCRUED REVENUE - EERA - ME -Residential	Revenue	Active
304901724950106	ACCRUED REVENUE-LDAC-EEC-SMALL C&I	Revenue	Active
305901734950106	ACCRUED REVENUE - EERA - ME -Small C&I	Revenue	Active
304913104950500	NON-TRADITIONAL SALES MARGIN - PEAK - NH	Revenue	Active
305913104950500	NON-TRADITIONAL SALES MARGIN - PEAK - ME	Revenue	Active
305913154950500	NON-TRADITIONAL SALES MARGIN - PEAK	Revenue	Active
305913454950500	NON-TRADITIONAL SALES MARGIN - OFF PEAK	Revenue	Active
304010004951000	UNBILLED GAS REVENUE - NH	Revenue	Active
305010004951000	UNBILLED GAS REVENUE - ME	Revenue	Active
304010004951001	UNBILLED REVENUE - SEASONALITY	Revenue	Active
305010004951001	UNBILLED REVENUE - SEASONALITY	Revenue	Active
304010004953000	ACCRUED REVENUE - OTHER	Revenue	Active
305010004953000	ACCRUED REVENUE - OTHER	Revenue	Active
304008004955000	RATE RELIEF - NU NH	Revenue	Active
305008004955000	RATE RELIEF - NU ME	Revenue	Active
304008004960000	RESERVED RATE CASE REVENUE	Revenue	Active
304080007100000	LPG-OPER SUPERVIS - MISC	Expense	Active
305085007100000	PROD OPER GEN SUPERVIS	Expense	Active
304901107100488	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - NH	Expense	Active
304901407100488	PRODUCTION & STORAGE ALLOW -DEMAND - OFF PEAK - NH	Expense	Active

Account Code	Description	Type	Status
305901107100488	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - ME	Expense	Active
305901407100488	PRODUCTION & STORAGE ALLOW -DEMAND - OFF PEAK - ME	Expense	Active
304901107100499	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - NH	Expense	Active
304901407100499	PRODUCTION & STORAGE ALLOW -DEMAND - OFF PEAK - NH	Expense	Active
305901107100499	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - ME	Expense	Active
305901407100499	PRODUCTION & STORAGE ALLOW -DEMAND - OFF PEAK - ME	Expense	Active
304080007170000	PROD OPER LABOR LPG - NH	Expense	Active
305085007170000	PROD OPER LABOR LPG - ME	Expense	Active
300080007170100	PROD OPER LABOR LNG - COMMON	Expense	Active
304080007170100	PROD OPER LABOR LNG - NH	Expense	Active
305085007170100	PROD OPER LABOR LNG - ME	Expense	Active
304080007170200	PROD OPER LABOR OTHER - NH	Expense	Active
305085007170200	PROD OPER LABOR OTHER - ME	Expense	Active
304080007170300	LPG-VAPORIZATION EXP	Expense	Active
305085007170300	LPG-VAPORIZATION EXP	Expense	Active
304026007180000	DISPATCHING PRODUCTION - NH	Expense	Active
304080007180000	DISPATCHING PRODUCTION - NH	Expense	Active
305026007180000	DISPATCHING PRODUCTION - ME	Expense	Active
305085007180000	DISPATCHING PRODUCTION - ME	Expense	Active
304080007190000	LPG-LOADG/UNLOADG-MISC - NH	Expense	Active
305085007190000	LPG-LOADG/UNLOADG-MISC - ME	Expense	Active
300080007230000	FUEL FOR LPG PROCESS - COMMON	Expense	Active
304080007230000	FUEL FOR LPG PROCESS - NH	Expense	Active
305085007230000	FUEL FOR LPG PROCESS - ME	Expense	Active
300013107230101	LPG PROCESS DEMAND - COMMON - PEAK	Expense	Active
300013407230101	LPG PROCESS DEMAND - COMMON - OFF PEAK	Expense	Active
304913107230101	LPG PROCESS DEMAND - PEAK - NH	Expense	Active
305913107230101	LPG PROCESS DEMAND -PEAK - ME	Expense	Active
300013107230102	LPG PROCESS COMMODITY - COMMON - PEAK	Expense	Active
304010117230102	NH LPG EXPENSE MISC - ELECTRIC PEAK	Expense	Active
304010417230102	NH LPG EXPENSE MISCELLANEOUS - ELECTRIC OFF PEAK	Expense	Active
304080117230102	NH LPG EXPENSE MISCELLANEOUS - ELECTRIC PEAK	Expense	Active
304080417230102	NH LPG EXPENSE MISCELLANEOUS - ELECTRIC OFF PEAK	Expense	Active
304913117230102	LPG PROCESS COMMODITY - PEAK - NH	Expense	Active
304913417230102	LPG PROCESS COMMODITY - OFF PEAK - NH	Expense	Active
305913157230102	LPG PROCESS COMMODITY - PEAK - ME	Expense	Active
305913457230102	LPG PROCESS COMMODITY - OFF PEAK - ME	Expense	Active
305985157230102	ME LPG FUEL / VAPORIZED - ELECTRIC PEAK	Expense	Active
305985457230102	ME LPG FUEL / VAPORIZED - ELECTRIC OFF PEAK	Expense	Active
300013107280101	LPG VAPORIZED FOR SENDOUT - DEMAND - PEAK - NH	Expense	Active
300013407280101	LPG VAPORIZED FOR SENDOUT - DEMAND - COMMON - OFF PEAK	Expense	Active
304913107280101	LPG VAPORIZED FOR SENDOUT - DEMAND - PEAK - NH	Expense	Active
305913107280101	LPG VAPORIZED FOR SENDOUT - DEMAND - PEAK - ME	Expense	Active
300013107280102	LPG VAPORIZED FOR SENDOUT - COMMODITY - COMMON - PEAK	Expense	Active
305913157280102	LPG VAPORIZED FOR SENDOUT - COMMODITY - ME - PEAK	Expense	Active
305913457280102	LPG VAPORIZED FOR SENDOUT - COMMODITY - ME - OFF PEAK	Expense	Active
304080007350000	TELEPHONE EXPENSE - NH	Expense	Active
304080007350100	PROD OPER MISC EXPENSE - NH	Expense	Active
304901737350100	ERC AMORTIZATION - NH	Expense	Active
305010007350100	PROD OPER MISC EXPENSE- ME	Expense	Active
305085007350100	PROD OPER MISC EXPENSE- ME	Expense	Active
305901747350100	ERC AMORTIZATION - ME	Expense	Active
300080007350300	PROD INSPECTIONS & ALARMS LPGA - COMMON	Expense	Active
304080007350300	PROD INSPECTIONS & ALARMS LPGA - NH	Expense	Active
305085007350300	PROD INSPECTIONS & ALARMS LPGA - ME	Expense	Active
304080007350400	PROD UNPRODUCTIVE - NH	Expense	Active
305085007350400	PROD UNPRODUCTIVE - ME	Expense	Active
304080007350500	PROD INSPECTIONS & ALARMS LNG - NH	Expense	Active
305085007350500	PROD INSPECTIONS & ALARMS LNG - ME	Expense	Active
305901107350688	LNG & LP PROD & CAPACITY ALLOW-DEMAND-PEAK-ME	Expense	Active
305901107350699	LNG & LP PROD & CAPACITY ALLOW-DEMAND-PEAK-ME	Expense	Active
304080007400000	PROD MAINT GEN SUPERVISION - NH	Expense	Active
305085007400000	PROD MAINT GEN SUPERVISION - ME	Expense	Active
304080007410000	PROD MAINT STRUCT & IMP LPG - NH	Expense	Active

Account Code	Description	Type	Status
305085007410000	PROD MAINT STRUCT & IMP LPG - ME	Expense	Active
304080007410100	PROD MAINT STRUCT & IMP LNG - NH	Expense	Active
305085007410100	PROD MAINT STRUCT & IMP LNG - ME	Expense	Active
304080007420000	PROD MAINT E - EQUIPMENT - LPG - NH	Expense	Active
305085007420000	PROD MAINT E - EQUIPMENT - LPG - ME	Expense	Active
304080007420100	PROD MAINT E - EQUIPMENT - LNG - NH	Expense	Active
305085007420100	PROD MAINT E - EQUIPMENT - LNG - ME	Expense	Active
304080007430000	GAS SYS PRODUCTION TRAINING - NH	Expense	Active
305085007430000	GAS SYS PRODUCTION TRAINING - ME	Expense	Active
304080007500000	LNG OPERATION SUPERVISION & ENGINEERING - NH	Expense	Active
305085007500000	LNG OPERATION SUPERVISION & ENGINEERING - ME	Expense	Active
304080007590000	LNG OTHER EXPENSES - NH	Expense	Active
305085007590000	LNG OTHER EXPENSES - ME	Expense	Active
304080007690000	MAINT OF SCADA - PRODUCTION - NH	Expense	Active
305085007690000	MAINT OF SCADA - PRODUCTION - ME	Expense	Active
304080007750000	LNG-MISC PRODUCTION & OPERATIONS - NH	Expense	Active
305085007750000	LNG-MISC PRODUCTION & OPERATIONS - ME	Expense	Active
305985157750000	ME LNG FUEL / VAPORIZED - ELECTRIC PEAK	Expense	Active
304080007800000	LNG MAINT-SUPER & ENG-MISC - NH	Expense	Active
305085007800000	LNG MAINT-SUPER & ENG-MISC - ME	Expense	Active
304080007810000	LNG MAINT-STRUC & IMPROV-MISC - NH	Expense	Active
305085007810000	LNG MAINT-STRUC & IMPROV-MISC - ME	Expense	Active
300080007820000	LNG MAINT-EQUIPMENT - COMMON	Expense	Active
304080007820000	LNG MAINT-EQUIPMENT - NH	Expense	Active
305085007820000	LNG MAINT-EQUIPMENT - ME	Expense	Active
304080007870000	LPG-BAYNOR PRICE VAR.EXP	Expense	Active
305085007870000	LPG-BAYNOR PRICE VAR.EXP	Expense	Active
300013007980000	MISC MARGIN SHARING - COMMON	Expense	Active
304013007980000	MISC MARGIN SHARING - NH	Expense	Active
305013007980000	MISC MARGIN SHARING - ME	Expense	Active
304013007980200	UNBILLED TRANSPORTATION	Expense	Active
305013007980200	UNBILLED TRANSPORTATION	Expense	Active
304013007980300	RES TRNS RSS-1 & CASH OUT CHG	Expense	Active
305013007980300	RES TRNS RSS-1 & CASH OUT CHG	Expense	Active
304013007980400	OVERTAKE ENERGY CHARGE	Expense	Active
305013007980400	OVERTAKE ENERGY CHARGE	Expense	Active
304013007980500	DEF UNBILLED COMMODITY CHOICE	Expense	Active
305013007980500	DEF UNBILLED COMMODITY CHOICE	Expense	Active
304913107980600	CAPACITY RELEASE- PEAK - ALLOC TO NH	Expense	Active
305913107980600	CAPACITY RELEASE- PEAK - ME	Expense	Active
304913107980601	CAPACITY RELEASE- PEAK - NH	Expense	Active
305913107980601	CAPACITY RELEASE- PEAK - ME	Expense	Active
304913107980602	PIPELINE CAPACITY RELEASE - CAP ASSIGN - PEAK - NH	Expense	Active
305913107980602	CAPACITY RELEASE- PEAK - CIS CUST REENTRY FEE -ME	Expense	Active
304913107980603	STORAGE CAPACITY RELEASE - CAP ASSIGN - PEAK - NH	Expense	Active
304913107980604	ASSET MGT CREDITS ALLOC TO NH	Expense	Active
305913107980604	ASSET MGT CREDITS ALLOC TO ME	Expense	Active
304913107980605	ASSET MGT CR - PNGTS CASE COSTS	Expense	Active
304013007981200	UNBILLED PURCH -RES, COM&IND	Expense	Active
305013007981200	UNBILLED PURCH -RES, COM&IND	Expense	Active
304013007981300	INTERR COSTS TRANSPORTATION	Expense	Active
305013007981300	INTERR COSTS TRANSPORTATION	Expense	Active
304013007981500	NAT EXP.-BAYNOR PRICE VAR.	Expense	Active
305013007981500	NAT EXP-BAYNOR PRICE VAR	Expense	Active
304913107986090	CAPACITY RELEASE- PEAK EST - NH	Expense	Active
305913107986090	CAPACITY RELEASE- PEAK EST- ME	Expense	Active
304913107990102	PIPELINE CAPACITY MITIGATION - PEAK - NH	Expense	Active
304913107990202	STORAGE CAPACITY MITIGATION - PEAK - NH	Expense	Active
304913107990399	CAPACITY MITIGATION - PEAK - NH	Expense	Active
304913107991290	CAPACITY MITIGATION - PIPELINE - PEAK EST - NH	Expense	Active
304913107992290	CAPACITY MITIGATION - STORAGE- PEAK EST - NH	Expense	Active
304013008000200	PASSBACK OF INTER. PROFITS	Expense	Active
305013008000200	PASSBACK OF INTER. PROFITS	Expense	Active
304013008000300	UNBILLED CGA-PRIOR PD DEFICIEN	Expense	Active

Account Code	Description	Type	Status
305013008000300	UNBILLED CGA-PRIOR PD DEFICIEN	Expense	Active
304013008000400	INTERRUPTIBLE TRANSP. MARGIN	Expense	Active
304013008000600	ADJ. PRIOR YEAR-NON CGA ITEM	Expense	Active
305013008000600	ADJ. PRIOR YEAR-NON CGA ITEM	Expense	Active
304001008040099	INTERRUPTIBLE COSTS - MARGIN	Expense	Active
304901108040099	DEFERRAL OF INTERRUPTIPLE PROFITS NH-WINTER	Expense	Active
304901118040099	INTERRUPTIBLE COSTS - MARGIN-WINTER	Expense	Active
304901408040099	DEFERRAL OF INTERRUPTIPLE PROFITS NH-SUMMER	Expense	Active
304901418040099	INTERRUPTIBLE COSTS - MARGIN-SUMMER	Expense	Active
305001008040099	INTERRUPTIBLE COSTS - MARGIN	Expense	Active
305901108040099	DEFERRAL OF INTERRUPTIPLE PROFITS ME-WINTER	Expense	Active
305901158040099	INTERRUPTIBLE COSTS - MARGIN-WINTER	Expense	Active
305901458040099	INTERRUPTIBLE COSTS - MARGIN- OFF PEAK	Expense	Active
304910408040101	DEMAND - NH - OFF PEAK	Expense	Active
304913108040101	TRANSPORTATION - DEMAND - PEAK - NH	Expense	Active
304913408040101	TRANSPORTATION - DEMAND - OFF PEAK - ME	Expense	Active
305910408040101	DEMAND - ME - OFF PEAK	Expense	Active
305913108040101	TRANSPORTATION - DEMAND - PEAK - ME	Expense	Active
305913408040101	TRANSPORTATION - DEMAND - OFF PEAK - ME	Expense	Active
304913108040102	GRANITE PURCHASE- DEMAND- PEAK - NH	Expense	Active
304913118040102	TRANSPORTATION COMMODITY - PEAK - NH	Expense	Active
304913418040102	TRANSPORTATION COMMODITY - OFF PEAK - NH	Expense	Active
305913108040102	GRANITE PURCHASE- DEMAND- PEAK - ME	Expense	Active
305913158040102	TRANSPORTATION COMMODITY - PEAK - ME	Expense	Active
305913458040102	TRANSPORTATION COMMODITY- OFF PEAK - ME	Expense	Active
304001008040199	EMERGENCY SALES MARGIN	Expense	Active
304901118040199	EMERGENCY SALES MARGIN-WINTER	Expense	Active
304901418040199	EMERGENCY SALES MARGIN-SUMMER	Expense	Active
305001008040199	EMERGENCY SALES MARGIN	Expense	Active
305901158040199	EMERGENCY SALES MARGIN-WINTER	Expense	Active
305901458040199	EMERGENCY SALES MARGIN-OFF PEAK	Expense	Active
304913108040201	SUPPLY PURCHASES - DEMAND - PEAK - NH	Expense	Active
305913108040201	SUPPLY PURCHASES - DEMAND - PEAK - ME	Expense	Active
304913118040202	SUPPLY PURCHASES COMMODITY- PEAK - NH	Expense	Active
304913418040202	SUPPLY PURCHASES - COMMODITY- OFF PEAK - NH	Expense	Active
305913158040202	SUPPLY PURCHASES COMMODITY- PEAK - ME	Expense	Active
305913458040202	SUPPLY PURCHASES COMMODITY- OFF PEAK - ME	Expense	Active
304913118040205	COMPANY MANAGED - PEAK - NH	Expense	Active
304913418040205	COMPANY MANAGED - OFF PEAK - NH	Expense	Active
305913158040205	COMPANY MANAGED - PEAK - ME	Expense	Active
305913458040205	COMPANY MANAGED - OFF PEAK - ME	Expense	Active
304910108040302	PEAK DEMAND CHARGES DEFERRED - NH	Expense	Active
304913108040302	PEAK DEMAND CHARGES DEFERRED - NH	Expense	Active
305910108040302	PEAK - DEMAND CHARGES DEFERRED - ME	Expense	Active
305913108040302	PEAK DEMAND CHARGES DEFERRED - ME	Expense	Active
304913118040401	ATV RECON CHARGES - PEAK - NH	Expense	Active
304913418040401	ATV RECON CHARGES - OFF PEAK - NH	Expense	Active
305913158040401	ATV RECON CHARGES - PEAK - ME	Expense	Active
305913458040401	ATV RECON CHARGES - OFF PEAK - ME	Expense	Active
304913108041190	TRANSP - DEMAND - PEAK EST - NH	Expense	Active
304913408041190	TRANSP - DEMAND - OFF PEAK EST - NH	Expense	Active
305913108041190	TRANSP - DEMAND - PEAK EST - ME	Expense	Active
305913408041190	TRANSP - DEMAND - OFF PEAK EST - ME	Expense	Active
304913118041290	TRANSPORTATION VARIABLE - PEAK EST - NH	Expense	Active
304913418041290	TRANSPORTATION VARIABLE - OFF PEAK EST - NH	Expense	Active
305913158041290	TRANSPORTATION VARIABLE - PEAK EST - ME	Expense	Active
305913458041290	TRANSPORTATION VARIABLE - OFF PEAK EST - ME	Expense	Active
304913108042190	SUPPLY PURCHASES -DEMAND- PEAK EST - NH	Expense	Active
305913108042190	SUPPLY PURCHASES - DEMAND- PEAK EST - ME	Expense	Active
304913118042290	SUPPLY PURCHASES COMMODITY- PEAK EST - NH	Expense	Active
304913418042290	SUPPLY PURCHASES COMMODITY- OFF PEAK EST - NH	Expense	Active
305913158042290	SUPPLY PURCHASES COMMODITY- PEAK EST - ME	Expense	Active
305913458042290	SUPPLY PURCHASES COMMODITY- OFF PEAK EST - ME	Expense	Active
304010008050200	UNBILLED GAS GAS COST - RESIDENTIAL - NH	Expense	Active

Account Code	Description	Type	Status
305010008050200	UNBILLED GAS GAS COST - RESIDENTIAL - ME	Expense	Active
304010008050300	UNBILLED GAS GAS COST - COMMERCIAL - NH	Expense	Active
305010008050300	UNBILLED GAS GAS COST - COMMERCIAL - ME	Expense	Active
304010008050400	UNBILLED GAS GAS COST - INDUSTRIAL - NH	Expense	Active
305010008050400	UNBILLED GAS GAS COST - INDUSTRIAL - ME	Expense	Active
304010008050500	UNBILLED TRANSPORTATION - NH	Expense	Active
305010008050500	UNBILLED TRANSPORTATION - ME	Expense	Active
304913118060100	GRANITE OBA - NH - PEAK	Expense	Active
304913418060100	GRANITE OBA - NH - OFF PEAK	Expense	Active
305913158060100	GRANITE OBA - ME - PEAK	Expense	Active
305913458060100	GRANITE OBA - ME - OFF PEAK	Expense	Active
304913108070000	HEDGING COSTS - DEMAND - PEAK - NH	Expense	Active
304913118070000	HEDGING - COMMODITY - NH - PEAK	Expense	Active
305913108070000	HEDGING COSTS - DEMAND - PEAK - ME	Expense	Active
305913158070000	HEDGING - COMMODITY - ME - PEAK	Expense	Active
304913418070001	HEDGING COSTS - COMMODITY - OFF PEAK - NH	Expense	Active
305913458070001	HEDGING COSTS - COMMODITY - OFF PEAK - ME	Expense	Active
300010008070100	USC - PURCHASED GAS (DISPATCH)	Expense	Active
304010008070100	USC - PURCHASED GAS (DISPATCH)	Expense	Active
305010008070100	USC - PURCHASED GAS (DISPATCH)	Expense	Active
304010008070200	CORPORATE SERVICES ESTIMATE	Expense	Active
305010008070200	CORPORATE SERVICES ESTIMATE	Expense	Active
304010008070300	CORPORATE SERVICES ACTUAL	Expense	Active
305010008070300	CORPORATE SERVICES ACTUAL	Expense	Active
304010008070400	CGA INCL STATE TAXES -CURRENT	Expense	Active
305010008070400	CGA INCL STATE TAXES -CURRENT	Expense	Active
305010008070500	CGA INCL. STATE TAXES-PRIOR	Expense	Active
304913108080000	LNG USED TO VAPORIZE - DEMAND - PEAK - NH	Expense	Active
305913108080000	LNG USED TO VAPORIZE - DEMAND - PEAK - ME	Expense	Active
305913158080001	LNG USED TO VAPORIZE LNG - COMMODITY - PEAK - ME	Expense	Active
305913458080001	LNG USED TO VAPORIZE LNG - COMMODITY - OFF PEAK - ME	Expense	Active
304913108080090	LNG USED TO VAPORIZE - DEMAND - PEAK EST - NH	Expense	Active
304913108080100	LNG VAPORIZED FOR SENDOUT - DEMAND - PEAK - NH	Expense	Active
305913108080100	LNG VAPORIZED FOR SENDOUT - DEMAND - PEAK - ME	Expense	Active
304913118080101	NH LNG VAPORIZED FOR SENDOUT PEAK	Expense	Active
304913418080101	LNG VAPORIZED FOR SENDOUT - COMMODITY - OFF PEAK - NH	Expense	Active
305913158080101	LNG VAPORIZED FOR SENDOUT - COMMODITY - PEAK - ME	Expense	Active
305913458080101	LNG VAPORIZED FOR SENDOUT - COMMODITY - OFF PEAK - ME	Expense	Active
304913108080200	STORAGE COSTS -DEMAND - PEAK - NH	Expense	Active
304913118080200	INVENTORY STORAGE WITHDRAWAL - NH - PEAK	Expense	Active
304913418080200	INVENTORY STORAGE WITHDRAWAL-NH-OFF PEAK	Expense	Active
305913108080200	STORAGE COSTS -DEMAND - PEAK - ME	Expense	Active
305913158080200	INVENTORY STORAGE WITHDRAWAL - ME - PEAK	Expense	Active
305913458080200	INVENTORY STORAGE WITHDRAWAL-ME-OFF PEAK	Expense	Active
304913118080201	STORAGE COSTS - COMMODITY - PEAK - NH	Expense	Active
304913418080201	STORAGE COSTS - COMMODITY - OFF PEAK - NH	Expense	Active
305913158080201	STORAGE COSTS - COMMODITY - PEAK - ME	Expense	Active
305913458080201	STORAGE COSTS - COMMODITY - OFF PEAK - ME	Expense	Active
304913118081090	NATURAL GAS INJECTION - COMMODITY PEAK EST - NH	Expense	Active
304913418081090	NATURAL GAS INJECTION - COMMODITY OFF PEAK EST - NH	Expense	Active
305913158081090	NATURAL GAS INJECTION - COMMODITY PEAK EST - ME	Expense	Active
305913458081090	NATURAL GAS INJECTION - COMMODITY OFF PEAK EST - ME	Expense	Active
304913108082090	STORAGE COSTS -DEMAND - PEAK EST - NH	Expense	Active
305913108082090	STORAGE COSTS -DEMAND - PEAK EST - ME	Expense	Active
304913118082190	STORAGE WITHDRAWLS - PEAK EST - NH	Expense	Active
304913418082190	STORAGE WITHDRAWLS - OFF PEAK EST - NH	Expense	Active
305913158082190	STORAGE WITHDRAWLS - PEAK EST - ME	Expense	Active
305913458082190	STORAGE WITHDRAWLS - OFF PEAK EST - ME	Expense	Active
304913118120000	COMPANY USE - PEAK - NH	Expense	Active
304913418120000	COMPANY USE - OFF PEAK - NH	Expense	Active
305913158120000	COMPANY USE - PEAK - ME	Expense	Active
305913458120000	COMPANY USE - OFF PEAK - ME	Expense	Active
300013008130000	OTHER GAS SUPPLY EXP - COMMON	Expense	Active
304013008130000	OTHER GAS SUPPLY EXP - NH	Expense	Active

Account Code	Description	Type	Status
305013008130000	OTHER GAS SUPPLY EXP - ME	Expense	Active
300010008130100	USC-GAS PRODUCTION OTHER - COMMON	Expense	Active
300013008130100	USC-GAS PRODUCTION OTHER - COMMON	Expense	Active
304010008130100	USC-GAS PRODUCTION OTHER - NH	Expense	Active
304013008130100	USC-GAS PRODUCTION OTHER - NH	Expense	Active
305010008130100	USC-GAS PRODUCTION OTHER - ME	Expense	Active
305013008130100	USC-GAS PRODUCTION OTHER - ME	Expense	Active
304010008130200	OVER/UNDER COLLECTION W/CAP	Expense	Active
305010008130200	OVER/UNDER COLLECTION W/CAP	Expense	Active
304010008140100	DSM-AMORT IMPLE RES HEAT	Expense	Active
304010008140200	DSM-AMORT IMPLE RES NONHEAT	Expense	Active
304010008140300	DSM-AMORT IMPLE C&I RECOVERY	Expense	Active
304010008140800	NH RATE REDESIGN AMORTIZATION	Expense	Active
304080008500000	T&D OPER GEN SUPERVISION - NH	Expense	Active
305085008500000	T&D OPER GEN SUPERVISION - ME	Expense	Active
304080008510000	SYSTEM CTRL & LOAD DISPATCHING - COMMON	Expense	Active
305085008510000	SYSTEM CTRL & LOAD DISPATCHING - ME	Expense	Active
304010008510200	USC- DISPATCH	Expense	Active
305010008510200	USC- DISPATCH	Expense	Active
304026008520000	COMMUNICATION SYSTEM EXP - NU NH	Expense	Active
304080008520000	COMMUNICATION SYSTEM EXP - NH	Expense	Active
305026008520000	COMMUNICATION SYSTEM EXP - NU ME	Expense	Active
305085008520000	COMMUNICATION SYSTEM EXP - ME	Expense	Active
304080008560000	MAINS EXPENSE-WOMS - NH	Expense	Active
304080008570000	T&D OPER MEAS & REGULATG STN - NH	Expense	Active
305085008570000	T&D OPER MEAS & REGULATG STNQ - ME	Expense	Active
304080008579600	MEAS+REG.STA-STORERM EXP	Expense	Active
305085008579600	MEAS+REG.STA-STORERM EXP	Expense	Active
304080008590000	OTHER TRANSMISSION EXP-WOMS - NH	Expense	Active
305085008590000	OTHER TRANSMISSION EXP-WOMS - ME	Expense	Active
305085008630000	MAINT OF MAINS-MISC -WOMS - ME	Expense	Active
304080008700000	DISTRIBUTION OPERATION SUPERVISION - NH	Expense	Active
305085008700000	DISTRIBUTION OPERATION SUPERVISION - ME	Expense	Active
304080008700100	CORPORATE SERVICES	Expense	Active
305085008700100	CORPORATE SERVICES	Expense	Active
304080008740000	MISC EXP MAINS AND SERVICES	Expense	Active
305085008740000	T&D OPER MAINS AND SERVICES - ME	Expense	Active
304080008740100	GAS SYSTEM TRAINING - NH	Expense	Active
305085008740100	GAS SYSTEM TRAINING - ME	Expense	Active
304080008740200	DISTRIBUTION VALVE MAINTENANCE-NH	Expense	Active
305085008740200	DISTRIBUTION VALVE MAINTENANCE- ME	Expense	Active
304080008740300	STANDY COVERAGE - GAS	Expense	Active
305085008740300	STANDBY COVERAGE GAS- ME	Expense	Active
304080008740400	DIG SAFE EXPENSE - NH	Expense	Active
305085008740400	DIG SAFE EXPENSE - ME	Expense	Active
304080008740401	DIG SAFE EXPENSE - HIGH RISK- NH	Expense	Active
305085008740401	DIG SAFE EXPENSE - HIGH RISK- ME	Expense	Active
304080008740500	SERVICE LINE SURVEY - NH	Expense	Active
305085008740500	SERVICE LINE SURVEY - ME	Expense	Active
304080008740600	PUBLIC BUILDING SURVEY - NH	Expense	Active
305085008740600	PUBLIC BUILDING SURVEY - ME	Expense	Active
304080008740700	GAS MAIN SURVEY - NH	Expense	Active
305085008740700	GAS MAIN SURVEY - ME	Expense	Active
304080008740800	HIGH RISK BRIDGE SURVEY	Expense	Active
305085008740800	BRIDGE SURVEY	Expense	Active
304080008740900	OUTSIDE LEAK INVESIGATION	Expense	Active
305085008740900	OUTSIDE LEAK INVESTIGATION	Expense	Active
304080008741000	CRITICAL VALVE INSPECTIONS	Expense	Active
305085008741000	MAINTENANCE OF REIGHT OF WAYS	Expense	Active
304080008741100	MAINS&SERVICES-MAPS	Expense	Active
305085008741100	CRITICAL VALVE INSPECTIONS	Expense	Active
304080008741200	MAINS+SERV-UNIFORMS EXP	Expense	Active
305085008741200	MAINS+SERV-UNIFORMS EXP	Expense	Active
304080008741300	MAINS+SERV- C/S ODOR INVEST	Expense	Active

Account Code	Description	Type	Status
305085008741300	MAINS+SERV- C/S ODOR INVEST	Expense	Active
304080008741400	MAINS&SERV-MAPS UPDTED-W.O.M.S	Expense	Active
305085008741400	MAINS&SERV-MAPS UPDTED-W.O.M.S	Expense	Active
304080008741500	MAINS&SERV-LOCATES	Expense	Active
305085008741500	MAINS&SERV-LOCATES	Expense	Active
304080008741600	MAINS&SERV-LEAK INVEST	Expense	Active
305085008741600	MAINS&SERV-LEAK INVEST	Expense	Active
304080008741700	MAINS&SERV-MOBIL	Expense	Active
305085008741700	MAINS&SERV-MOBIL	Expense	Active
304080008741800	MAINS&SERV-MANHOLE	Expense	Active
305085008741800	MAINS&SERV-MANHOLE	Expense	Active
304080008741900	R.O.W. CLEARING	Expense	Active
305085008741900	R.O.W. CLEARING	Expense	Active
304080008742000	STANDBY FOR BLASTING	Expense	Active
305085008742000	STANDBY FOR BLASTING	Expense	Active
304080008742100	MAINS&SERV-PBLC BLDG SRV	Expense	Active
305085008742100	MAINS&SERV-PBLC BLDG SRV	Expense	Active
304080008742200	MAINS+SERV-STOREROOM EXP.	Expense	Active
305085008742200	MAINS+SERV-STOREROOM EXP.	Expense	Active
304080008742300	MAINS+SERV-NON-PROD	Expense	Active
305085008742300	MAINS+SERV-NON-PROD	Expense	Active
304080008742400	MAINS+SERV-TRANSP	Expense	Active
305085008742400	MAINS+SERV-TRANSP	Expense	Active
304080008750000	REG STATION EXPENSE (GEN) - NH	Expense	Active
305085008750000	REG STATION EXPENSE (GEN) - ME	Expense	Active
300026008750001	INTERVAL DATA NU COMMON	Expense	Active
304026008750001	INTERVAL DATA NU NH	Expense	Active
305026008750001	INTERVAL DATA NU ME	Expense	Active
304080008750100	SYSTEM OPS STANDBY	Expense	Active
305085008750100	SYSTEM OPS STANDBY	Expense	Active
304080008750200	SYSTEM OPS UPRODUCTIVE	Expense	Active
305085008750200	SYSTEM OPS UNPRODUCTIVE	Expense	Active
304080008750300	SYSTEM OPS TRAINING	Expense	Active
305085008750300	SYSTEM OPS TRAINING	Expense	Active
304080008750400	REGULATION SUPERVISION	Expense	Active
305085008750400	REGULATION SUPERVISION	Expense	Active
304080008750800	MTR & HSE REG - INVESTIGATE METER READING	Expense	Active
304080008750900	MTR & HSE REG - INVESTIGATE DEVICE/ERT	Expense	Active
304080008770000	C/S PARTS - NH	Expense	Active
305085008770000	C/S PARTS - ME	Expense	Active
304080008780000	METER ORDERS - GENERAL	Expense	Active
305085008780000	METER ORDERS - GENERAL	Expense	Active
300026008780100	METER ORDERS - COMMON	Expense	Active
304026008780100	METER ORDERS - NH	Expense	Active
304080008780100	METERTURN ON & OFFS - NH	Expense	Active
305026008780100	METER ORDERS - ME	Expense	Active
305085008780100	METERS-TURN ON & OFFS - ME	Expense	Active
304080008780200	METERS-REMOVES & INSTALLS - NH	Expense	Active
305085008780200	METER CHANGES- ME	Expense	Active
304080008780300	REPAIR FIT LEAKS - NH	Expense	Active
305085008780300	REPAIR FIT LEAKS - ME	Expense	Active
304080008780400	SERVICING GAS METER BRACKETS	Expense	Active
305085008780400	SERVICING GAS METER BRACKETS	Expense	Active
304080008780401	METER & SERVICE TRANSPORTATION EXP	Expense	Active
305085008780401	METER & SERVICE TRANSPORTATION EXP	Expense	Active
304080008780500	M&S UNPRODUCTIVE TIME	Expense	Active
305085008780500	M&S UNPRODUCTIVE TIME	Expense	Active
304080008780501	M&S UNPRODUCTIVE TIME - SICK	Expense	Active
304080008780502	M&S UNPRODUCTIVE TIME - HOLIDAY	Expense	Active
304080008780503	M&S UNPRODUCTIVE TIME - VACATION	Expense	Active
304080008780504	M&S UNPRODUCTIVE TIME - OTHER	Expense	Active
304080008780600	METER & SERVICE SUPERVISION	Expense	Active
305085008780600	METER & SERVICE SUPERVISION	Expense	Active
304080008780700	MTR & HSE REG - READ IN/OUTS - NH	Expense	Active

Account Code	Description	Type	Status
305085008780700	MTR & HSE REG - READ IN/OUTS - ME	Expense	Active
304080008780800	MTR & HSE REG-INVESTIGATE METER READING	Expense	Active
305085008780800	MTR & HSE REG-INVESTIGATE METER READING ME	Expense	Active
304080008780900	MTR & HSE REG - INVESTIGATE DEVICE/ERT	Expense	Active
305085008780900	MTR & HSE REG-INVESTIGATE DEVICE/ERT ME	Expense	Active
304080008781000	MTR & HSE REG - CHG MTR ERT - NH	Expense	Active
305085008781000	MTR & HSE REG - CHG MTR ERT - ME	Expense	Active
304010008781100	SVC CENTER CAPITALIZED- NH	Expense	Active
305010008781100	SVC CENTER CAPITALIZED- ME	Expense	Active
304010008781200	SVC CENTER EXPENSED- NH	Expense	Active
300026008781300	MTR & HSE REG - MISC - COMMON	Expense	Active
304026008781300	MTR & HSE REG - MISC - NH	Expense	Active
304080008781300	MTR & HSE REG - TRAINING - EM&C NH	Expense	Active
305026008781300	MTR & HSE REG - MISC - ME	Expense	Active
305085008781300	MTR & HSE REG - TRAINING - EM&C- ME	Expense	Active
300026008781400	MTR & HSE REG - REGUL - COMMON	Expense	Active
304026008781400	MTR & HSE REG - REGUL - NH	Expense	Active
304080008781400	MTR & HSE REG - MISC - EM&C NH	Expense	Active
305026008781400	MTR & HSE REG - REGUL - ME	Expense	Active
305085008781400	MTR & HSE REG - MISC-EM&C - ME	Expense	Active
300026008781500	MTR & HSE REG - MTR - COMMON	Expense	Active
304026008781500	MTR & HSE REG - MTR - NH	Expense	Active
304080008781500	MTR & HSE REG - MTR - NH	Expense	Active
305026008781500	MTR & HSE REG - MTR - ME	Expense	Active
305085008781500	MTR & HSE REG - MTR - ME	Expense	Active
300026008781600	MTR & HSE REG - ADMIN - COMMON	Expense	Active
304026008781600	MTR & HSE REG - ADMIN - NH	Expense	Active
304080008781600	MTR & HSE REG - ADMIN - NH	Expense	Active
305026008781600	MTR & HSE REG - ADMIN - ME	Expense	Active
305085008781600	MTR & HSE REG - ADMIN - ME	Expense	Active
300026008781700	MTR & HSE REG - UNLOCK - COMMON	Expense	Active
304026008781700	MTR & HSE REG - UNLOCK - NH	Expense	Active
304080008781700	MTR & HSE REG - UNLOCK - NH	Expense	Active
305026008781700	MTR & HSE REG - UNLOCK - ME	Expense	Active
305085008781700	MTR & HSE REG - UNLOCK - ME	Expense	Active
300026008781800	MTR & HSE REG - LOCK - COMMON	Expense	Active
304026008781800	MTR & HSE REG - LOCK - NH	Expense	Active
304080008781800	MTR & HSE REG - LOCK - NH	Expense	Active
305026008781800	MTR & HSE REG - LOCK - ME	Expense	Active
305085008781800	MTR & HSE REG - LOCK - ME	Expense	Active
300026008781900	MTR & HSE REG - REMOVE - COMMON	Expense	Active
304026008781900	MTR & HSE REG - REMOVE - NH	Expense	Active
304080008781900	MTR & HSE REG - REMOVE - NH	Expense	Active
305026008781900	MTR & HSE REG - REMOVE - ME	Expense	Active
305085008781900	MTR & HSE REG - REMOVE - ME	Expense	Active
300026008782000	MTR & HSE REG - READ - COMMON	Expense	Active
304026008782000	MTR & HSE REG - READ - NH	Expense	Active
304080008782000	MTR & HSE REG - READ - NH	Expense	Active
305026008782000	MTR & HSE REG - READ - ME	Expense	Active
305085008782000	MTR & HSE REG - READ - ME	Expense	Active
300026008782100	MTR & HSE REG - LT APPL AF - COMMON	Expense	Active
304026008782100	MTR & HSE REG - LT APPL AF - NH	Expense	Active
304080008782100	MTR & HSE REG - LT APPL AF - NH	Expense	Active
305026008782100	MTR & HSE REG - LT APPL AF - ME	Expense	Active
305085008782100	MTR & HSE REG - LT APPL AF - ME	Expense	Active
300026008782200	MTR & HSE REG - PT RES - COMMON	Expense	Active
304026008782200	MTR & HSE REG - PT RES - NH	Expense	Active
304080008782200	MTR & HSE REG - PT RES - NH	Expense	Active
305026008782200	MTR & HSE REG - PT RES - ME	Expense	Active
305085008782200	MTR & HSE REG - PT RES - ME	Expense	Active
300026008782300	MTR & HSE REG - PT C&I - COMMON	Expense	Active
304026008782300	MTR & HSE REG - PT C&I - NH	Expense	Active
304080008782300	MTR & HSE REG - PT C&I - NH	Expense	Active
305026008782300	MTR & HSE REG - PT C&I - ME	Expense	Active

Account Code	Description	Type	Status
305085008782300	MTR & HSE REG - PT C&I - ME	Expense	Active
300026008782400	MTR & HSE REG - CHG MTR FOR - COMMON	Expense	Active
304026008782400	MTR & HSE REG - CHG MTR FOR - NH	Expense	Active
304080008782400	MTR & HSE REG - CHG MTR FOR - NH	Expense	Active
305026008782400	MTR & HSE REG - CHG MTR FOR - ME	Expense	Active
305085008782400	MTR & HSE REG - CHG MTR FOR - ME	Expense	Active
300026008782500	MTR & HSE REG - CHG MTR TEST - COMMON	Expense	Active
304026008782500	MTR & HSE REG - CHG MTR TEST - NH	Expense	Active
304080008782500	MTR & HSE REG - CHG MTR TEST - NH	Expense	Active
305026008782500	MTR & HSE REG - CHG MTR TEST - ME	Expense	Active
305085008782500	MTR & HSE REG - CHG MTR TEST - ME	Expense	Active
300026008782600	MTR & HSE REG - CHG MTR ERT - COMMON	Expense	Active
304026008782600	MTR & HSE REG - CHG MTR ERT - NH	Expense	Active
304080008782600	MTR&HSE REG-CHGE MTR ERT-LARGE-NH	Expense	Active
305026008782600	MTR & HSE REG - CHG MTR ERT - ME	Expense	Active
305085008782600	MTR&HSE REG-CHGE MTR ERT-LARGE-ME	Expense	Active
300026008782700	MTR & HSE REG - INVEST - COMMON	Expense	Active
304026008782700	MTR & HSE REG - INVEST - NH	Expense	Active
304080008782700	MTR & HSE REG - INVEST - NH	Expense	Active
305026008782700	MTR & HSE REG - INVEST - ME	Expense	Active
305085008782700	MTR & HSE REG - INVEST - ME	Expense	Active
300026008782800	MTR & HSE REG - TOOLS & EQUP - COMMON	Expense	Active
304026008782800	MTR & HSE REG - TOOLS & EQUP - NH	Expense	Active
304080008782800	MTR & HSE REG - TOOLS & EQUP - NH	Expense	Active
305026008782800	MTR & HSE REG - TOOLS & EQUP - ME	Expense	Active
305085008782800	MTR & HSE REG - TOOLS & EQUP - ME	Expense	Active
300026008782900	MTR & HSE REG - UNIFORMS - COMMON	Expense	Active
304026008782900	MTR & HSE REG - UNIFORMS - NH	Expense	Active
304080008782900	MTR & HSE REG - UNIFORMS - NH	Expense	Active
305026008782900	MTR & HSE REG - UNIFORMS - ME	Expense	Active
305085008782900	MTR & HSE REG - UNIFORMS - ME	Expense	Active
300026008783000	MTR & HSE REG - MTR INSTRUM - COMMON	Expense	Active
304026008783000	MTR & HSE REG - MTR INSTRUM - NH	Expense	Active
304080008783000	MTR & HSE REG - MTR INSTRUM - NH	Expense	Active
305026008783000	MTR & HSE REG - MTR INSTRUM - ME	Expense	Active
305085008783000	MTR & HSE REG - MTR INSTRUM - ME	Expense	Active
300026008783100	MTR & HSE REG - TRAINING - COMMON	Expense	Active
304026008783100	MTR & HSE REG - TRAINING - NH	Expense	Active
304080008783100	MTR & HSE REG - TRAINING - NH	Expense	Active
305026008783100	MTR & HSE REG - TRAINING - ME	Expense	Active
305085008783100	MTR & HSE REG - TRAINING - ME	Expense	Active
300026008783200	MTR & HSE REG - READ INS OUTS - COMMON	Expense	Active
304026008783200	MTR & HSE REG - READ INS OUTS - NH	Expense	Active
304080008783200	MTR & HSE REG - READ INS OUTS - NH	Expense	Active
305026008783200	MTR & HSE REG - READ INS OUTS - ME	Expense	Active
305085008783200	MTR & HSE REG - READ INS OUTS - ME	Expense	Active
300026008783300	MTR & HSE REG - FLEET - COMMON	Expense	Active
304026008783300	MTR & HSE REG - FLEET - NH	Expense	Active
304080008783300	MTR & HSE REG - FLEET - NH	Expense	Active
305026008783300	MTR & HSE REG - FLEET - ME	Expense	Active
305085008783300	MTR & HSE REG - FLEET - ME	Expense	Active
300026008783400	MTR & HSE REG - STOREROOM - COMMON	Expense	Active
304026008783400	MTR & HSE REG - STOREROOM - NH	Expense	Active
304080008783400	MTR & HSE REG - STOREROOM - NH	Expense	Active
305026008783400	MTR & HSE REG - STOREROOM - ME	Expense	Active
305085008783400	MTR & HSE REG - STOREROOM - ME	Expense	Active
300026008783500	MTR & HSE REG - NON PROD - COMMON	Expense	Active
304026008783500	MTR & HSE REG - NON PROD - NH	Expense	Active
304080008783500	MTR & HSE REG - NON PROD - NH	Expense	Active
305026008783500	MTR & HSE REG - NON PROD - ME	Expense	Active
305085008783500	MTR & HSE REG - NON PROD - ME	Expense	Active
304080008788000	MTR & HSE REG - CHG MTR ERT - NH	Expense	Active
305085008788500	MTR & HSE REG - CHG MTR ERT - ME	Expense	Active
304080008788600	MTR & HSE REG - MTR INSTRUM MAINT - ME BY NH	Expense	Active

Account Code	Description	Type	Status
305085008788600	MTR & HSE REG - MTR INSTRUM MAINT - MAINT ME	Expense	Active
304080008790000	CUSTOMER LEAK INVESTIGATION - NH	Expense	Active
305085008790000	CUSTMR INSTALL-OTHER - ME	Expense	Active
304080008790100	EASY CARE SVC PLAN BASIC NO CHARGE NH	Expense	Active
305085008790100	T&D OPER CUSTMR INSTALLATIONS - ME	Expense	Active
305085008790200	CUST INSTALL - LEAK & ODOR - ME	Expense	Active
304080008790300	MISC CUST REPAIR-NO CHARGE - NH	Expense	Active
305085008790300	CUST INSTALL - TOOLS & EQUP - ME	Expense	Active
304080008790400	CUST INSTALL - TRAINING - NH	Expense	Active
305085008790400	CUST INSTALL - TRAINING - ME	Expense	Active
304080008790500	CUST INSTALL - OFFICE - NH	Expense	Active
305085008790500	CUST INSTALL - OFFICE - ME	Expense	Active
304080008790600	CUST INSTALL - UNIFORM - NH	Expense	Active
305085008790600	CUST INSTALL - UNIFORM - ME	Expense	Active
304080008790700	CUST INSTALL - INVESTIGATE - NH	Expense	Active
305085008790700	CUST INSTALL - INVESTIGATE - ME	Expense	Active
304080008790800	CUST INSTALL - SUPERVISION - NH	Expense	Active
305085008790800	CUST INSTALL - SUPERVISION - ME	Expense	Active
304080008790900	CUST INSTALL - GASLINE PROT - NH	Expense	Active
305085008790900	CUST INSTALL - GASLINE PROT - ME	Expense	Active
304080008791000	CUST INSTALL - BASIC LABOR - NH	Expense	Active
305085008791000	CUST INSTALL - BASIC LABOR - ME	Expense	Active
304080008791100	CUST INSTALL - PLUS LABOR - NH	Expense	Active
305085008791100	CUST INSTALL - PLUS LABOR - ME	Expense	Active
304080008791200	CUST INSTALL - PARTS - NH	Expense	Active
305085008791200	CUST INSTALL - PARTS - ME	Expense	Active
304080008791300	CUST INSTALL - FLEET - NH	Expense	Active
305085008791300	CUST INSTALL - FLEET - ME	Expense	Active
304080008791400	CUST INSTALL - STORES - NH	Expense	Active
305085008791400	CUST INSTALL - STORES - ME	Expense	Active
304080008791500	CUST INSTALL - NON PROD - NH	Expense	Active
305085008791500	CUST INSTALL - NON PROD - ME	Expense	Active
304080008792000	UNH EXPENSE- NH	Expense	Active
304080008800000	T&D OPER SYSTEM EXP - NH	Expense	Active
305085008800000	T&D OPER ADMIN EXP - ME	Expense	Active
304080008800100	GAS COMPLIANCE PROJECTS - NH	Expense	Active
305085008800100	GAS COMPLIANCE PROJECTS - ME	Expense	Active
300012008800200	USC-GAS DISTRIBUTION - COMMON	Expense	Active
300017008800200	USC-GAS DISTRIBUTION - COMMON	Expense	Active
300023008800200	USC-GAS DISTRIBUTION - COMMON	Expense	Active
300025008800200	USC-GAS DISTRIBUTION - COMMON	Expense	Active
304010008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
304012008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
304017008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
304023008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
304025008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
304026008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
304027008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
304028008800200	USC-GAS DISTRIBUTION - NH	Expense	Active
305010008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
305012008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
305017008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
305023008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
305025008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
305026008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
305027008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
305028008800200	USC-GAS DISTRIBUTION - ME	Expense	Active
300017008800201	USC - GAS DISTRIBUTION - COMMON-CAP	Expense	Active
304010008800201	USC-GAS DISTRIBUTION - NH-CAP	Expense	Active
304012008800201	USC-GAS DISTRIBUTION - NH-CAP	Expense	Active
304017008800201	USC - GAS DISTRIBUTION - NH-CAP	Expense	Active
304023008800201	USC-GAS DISTRIBUTION - NH-CAP	Expense	Active
304025008800201	USC-GAS DISTRIBUTION - NH-CAP	Expense	Active
304026008800201	USC-GAS DISTRIBUTION - NH-CAP	Expense	Active

Account Code	Description	Type	Status
304027008800201	USC-GAS DISTRIBUTION - NH-CAP	Expense	Active
304028008800201	USC-GAS DISTRIBUTION - NH-CAP	Expense	Active
305010008800201	USC-GAS DISTRIBUTION - ME-CAP	Expense	Active
305012008800201	USC-GAS DISTRIBUTION - ME-CAP	Expense	Active
305017008800201	USC - GAS DISTRIBUTION - ME-CAP	Expense	Active
305023008800201	USC-GAS DISTRIBUTION - ME-CAP	Expense	Active
305025008800201	USC-GAS DISTRIBUTION - ME-CAP	Expense	Active
305026008800201	USC-GAS DISTRIBUTION - ME-CAP	Expense	Active
305027008800201	USC-GAS DISTRIBUTION - ME-CAP	Expense	Active
305028008800201	USC-GAS DISTRIBUTION - ME-CAP	Expense	Active
304080008800300	OTHER EXPENSES-MISC - NH	Expense	Active
305085008800300	OTHER EXPENSES-MISC - ME	Expense	Active
304080008800400	OTHER EXP- CS POOR PRESSURE - COMMON	Expense	Active
305085008800400	OTHER EXP- CS POOR PRESSURE - COMMON	Expense	Active
304080008800500	OTHER EXP- CS ACTIVE - COMMON	Expense	Active
305085008800500	OTHER EXP- CS ACTIVE - COMMON	Expense	Active
304080008800600	OTHER EXP- LEAK - COMMON	Expense	Active
305085008800600	OTHER EXP- LEAK - COMMON	Expense	Active
304080008800700	OTHER EXP- INCL WEATHER - COMMON	Expense	Active
305085008800700	OTHER EXP- INCL WEATHER - COMMON	Expense	Active
304080008800800	OTHER EXP- FLEET - COMMON	Expense	Active
305085008800800	OTHER EXP- FLEET - COMMON	Expense	Active
304080008800900	OTHER EXP- STOREROOM - COMMON	Expense	Active
305085008800900	OTHER EXP- STOREROOM - COMMON	Expense	Active
305085008803000	MAINE NOPV DOCUMENTATION COSTS	Expense	Active
305085008803100	MAINE NOPV DOCUMENTATION COSTS ACCRUED	Expense	Active
304080008807900	SERVICE CORP ACTUAL	Expense	Active
305085008807900	SERVICE CORP ACTUAL	Expense	Active
304080008809900	COMPANY USE - NH	Expense	Active
305085008809900	COMPANY USE - ME	Expense	Active
300080008810000	RENTS-TRANSM & DISTRIB-MISC - COMMON	Expense	Active
304080008810000	RENTS-TRANSM & DISTRIB-MISC - NH	Expense	Active
305085008810000	RENTS-TRANSM & DISTRIB-MISC - ME	Expense	Active
304080008820000	METERING SYS - GAS TRAINING - NH	Expense	Active
305085008820000	METERING SYS - GAS TRAINING - ME	Expense	Active
300002008820100	REV C/S GC - COMMON	Expense	Active
304002008820100	REV C/S GC - NG	Expense	Active
305002008820100	REV C/S GC - ME	Expense	Active
304002008820200	REV C/S LBR - NH	Expense	Active
305002008820200	REV C/S LBR - ME	Expense	Active
304002008820300	REV C/S PART - NH	Expense	Active
305002008820300	REV C/S PART - ME	Expense	Active
304002008820400	REV GASLINE PROT - NH	Expense	Active
305002008820400	REV GASLINE PROT - ME	Expense	Active
304002008820500	REV GC COM PLANS - NH	Expense	Active
305002008820500	REV GC COM PLANS - ME	Expense	Active
304002008820600	REV GC LATE PMT	Expense	Active
305002008820600	REV GC LATE PMT - ME	Expense	Active
304002008820700	REV GC BASIC - NH	Expense	Active
305002008820700	REV GC BASIC - ME	Expense	Active
304002008820800	REV GC PLUS - NH	Expense	Active
305002008820800	REV GC PLUS - ME	Expense	Active
304002008820900	REV GC OPEN PLAN - NH	Expense	Active
305002008820900	REV GC OPEN PLAN - ME	Expense	Active
304002008821000	REV GC INTERCO ELIM - NH	Expense	Active
305002008821000	REV GC INTERCO ELIM - ME	Expense	Active
304002008821100	REV GC ANNUAL INSPECTION - NH	Expense	Active
305002008821100	REV GC ANNUAL INSPECTION - ME	Expense	Active
304002008821200	REV WH - NH	Expense	Active
305002008821200	REV WH - ME	Expense	Active
304002008821300	REV HH - NH	Expense	Active
305002008821300	REV HH - ME	Expense	Active
304002008821400	REV OTHER - NH	Expense	Active
304029008821400	REV OTHER - NH	Expense	Active

Account Code	Description	Type	Status
305002008821400	REV OTHER - ME	Expense	Active
304002008821500	REV DRY - NH	Expense	Active
305002008821500	REV DRY - ME	Expense	Active
304080008850000	MAINTENANCE GEN SUPERVISION - NH	Expense	Active
305085008850000	T&D MAINT GEN SUPERVISION - ME	Expense	Active
304080008850100	UNPROD TIME/SICKNESS - NH	Expense	Active
305085008850100	UNPROD TIME/SICKNESS - ME	Expense	Active
304080008850200	UNPROD TIME/WEATHER - NH	Expense	Active
305085008850200	UNPROD TIME/WEATHER - ME	Expense	Active
304080008850300	UNPROD TIME/HOLIDAYS - NH	Expense	Active
305085008850300	UNPROD TIME/HOLIDAYS - ME	Expense	Active
304080008850400	UNPROD TIME/VACATION - NH	Expense	Active
305085008850400	UNPROD TIME/VACATION - ME	Expense	Active
304080008850500	UNPROD TIME/OTHER - NH	Expense	Active
305085008850500	UNPROD TIME/OTHER - ME	Expense	Active
304010008850600	UNPROD TIME/CAPITALIZED - NH	Expense	Active
304080008850600	UNPROD TIME/CAPITALIZED - NH	Expense	Active
305010008850600	UNPROD TIME/CAPITALIZED - ME	Expense	Active
305085008850600	UNPROD TIME/CAPITALIZED - ME	Expense	Active
304080008860000	T&D MAINT STRUCTURES & IMPROV - NH	Expense	Active
305085008860000	T&D MAINT STRUCTURES & IMPROV - ME	Expense	Active
304080008870000	MAINT OF MAINS - NH	Expense	Active
305085008870000	T&D MAINT OF MAINS - ME	Expense	Active
304080008870100	MAINT OF MAINS LEAK REPAIR - CORROSION - NH	Expense	Active
305085008870100	MAINT OF MAINS LEAK REPAIR- ME	Expense	Active
304080008870101	MAINT OF MAINS TRANSPORTATION EXP- NH	Expense	Active
305085008870101	MAINT OF MAINS TRANSPORTATION EXP- ME	Expense	Active
305085008870200	T&D MAINT OF MAINS - LEAK - ME	Expense	Active
304080008870300	CORROSION MAINS - NH	Expense	Active
305085008870300	CORROSION MAINS - ME	Expense	Active
304080008870400	CORROSION BRIDGES - NH	Expense	Active
305085008870400	CORROSION BRIDGES - ME	Expense	Active
304080008870500	T&D MAINT OF MAINS - SAFETY - NH	Expense	Active
304080008870600	T&D MAINT OF MAINS - CONTRACT - NH	Expense	Active
305085008870600	T&D MAINT OF MAINS - CONTRACT - ME	Expense	Active
304080008870700	T&D MAINT OF MAINS - BRIDGE - COMMON	Expense	Active
305085008870700	T&D MAINT OF MAINS - BRIDGE - COMMON	Expense	Active
304080008870800	T&D MAINT OF MAINS - CRITICAL VALVES - COMMON	Expense	Active
305085008870800	T&D MAINT OF MAINS - CRITICAL VALVES - COMMON	Expense	Active
304080008870900	T&D MAINT OF MAINS - FLEET - NH	Expense	Active
305085008870900	T&D MAINT OF MAINS - FLEET - ME	Expense	Active
304080008871000	T&D MAINT OF MAINS - STOREROOM - NH	Expense	Active
305085008871000	T&D MAINT OF MAINS - STOREROOM - ME	Expense	Active
304080008871100	T&D MAINT OF MAINS - NON PROD - NH	Expense	Active
305085008871100	T&D MAINT OF MAINS - NON PROD - ME	Expense	Active
304080008890000	MAINT OF REG EQUIP (DISTRICT)- NH	Expense	Active
305085008890000	MAINT OF REG EQUIP (DISTRICT)- ME	Expense	Active
304080008890100	MAINT OF REG MAINT - NH	Expense	Active
305085008890100	MAINT OF REG MAINT - ME	Expense	Active
304080008890200	MAINT OF REG INSTRUMENT - NH	Expense	Active
305085008890200	MAINT OF REG INSTRUMENT - ME	Expense	Active
304080008890300	MAINT OF REG FLEET - NH	Expense	Active
305085008890300	MAINT OF REG FLEET - ME	Expense	Active
304080008890400	MAINT OF REG STORE - NH	Expense	Active
305085008890400	MAINT OF REG STORE - ME	Expense	Active
300080008900000	MAINT OF REG EQUIP (INDUST) - COMMON	Expense	Active
304080008900000	MAINT OF REG EQUIP (INDUST) - NH	Expense	Active
305085008900000	MAINT OF REG EQUIP (INDUST) - ME	Expense	Active
304080008910000	MAINT OF REG EQUIP (GATE STATION) - NH	Expense	Active
305085008910000	MAINT OF REG EQUIP (GATE STATION) - ME	Expense	Active
304080008910100	MAIN DISTRI SCADA -DISTRIBUTION- NH	Expense	Active
305085008910100	MAIN DISTRI SCADA - ME	Expense	Active
304080008920000	MAINT OF SERVICES - NH	Expense	Active
305085008920000	T&D MAINT OF SERVICES - ME	Expense	Active

Account Code	Description	Type	Status
304080008920100	CORROSION SERVICES- NH	Expense	Active
305085008920100	CORROSION SERVICES-ME	Expense	Active
305085008920200	MAINT SERV-RELOCATE - ME	Expense	Active
304080008921400	MAINT SERV- TRANSPORTATION EXP - NH	Expense	Active
305085008921400	MAINT SERV- TRANSPORTATION EXP - ME	Expense	Active
304080008921500	MAINT SERV- 3RD PARTY BILLING- NH	Expense	Active
305080008921500	MAINT SERV- 3RD PARTY BILLING- ME	Expense	Active
300026008930000	MAINT OF MTRS & HOUSE REGULTRS - COMMON	Expense	Active
304026008930000	MAINT OF MTRS & HOUSE REGULTRS - NH	Expense	Active
304080008930000	MAINT OF MTRS & HOUSE REGULTRS - NH	Expense	Active
305026008930000	MAINT OF MTRS & HOUSE REGULTRS - ME	Expense	Active
305085008930000	MAINT OF MTRS & HOUSE REGULTRS - ME	Expense	Active
300026008930100	MAINT METER - TESTING - COMMON	Expense	Active
304026008930100	MAINT METER - TESTING - NH	Expense	Active
305026008930100	MAINT METER - TESTING - NH	Expense	Active
305085008930100	MAINT METER - TESTING - NH	Expense	Active
300026008930200	MAINT METER HSE REG -CREDITS - COMMON	Expense	Active
304026008930200	MAINT METER HSE REG -CREDITS - NH	Expense	Active
304080008930200	MAINT METER HSE REG -CREDITS - NH	Expense	Active
305026008930200	MAINT METER HSE REG -CREDITS - ME	Expense	Active
305085008930200	MAINT METER HSE REG -CREDITS - ME	Expense	Active
300026008930300	MAINT METER - FLEET - COMMON	Expense	Active
304026008930300	MAINT METER - FLEET - NH	Expense	Active
304080008930300	MAINT METER - FLEET - NH	Expense	Active
305026008930300	MAINT METER - FLEET - ME	Expense	Active
305085008930300	MAINT METER - FLEET - ME	Expense	Active
300026008930400	MAINT METER - STOREROOM - COMMON	Expense	Active
304026008930400	MAINT METER - STOREROOM - NH	Expense	Active
304080008930400	MAINT METER - STOREROOM - NH	Expense	Active
305026008930400	MAINT METER - STOREROOM - ME	Expense	Active
305085008930400	MAINT METER - STOREROOM - ME	Expense	Active
304080008940000	T&D MAINT SYSTEM EQUIPMENT - NH	Expense	Active
305085008940000	T&D MAINT SYSTEM EQUIPMENT - ME	Expense	Active
304080008940100	MAINT OF SYSTEM OPS EQUIPMENT - NH	Expense	Active
304729508940100	WATER HEATER MAINTENANCE - GAS - NH	Expense	Active
304729518940100	NH ANNUAL INSPECTIONS- PARTS & LABOR	Expense	Active
304729528940100	CONVERSION BURNER MAINTENANCE - NH	Expense	Active
304729538940100	EASY CARE SVC PLAN PTS & LBR	Expense	Active
305085008940100	MAINT OF SYSTEM OPS EQUIPMENT - ME	Expense	Active
305729508940100	WATER HEATER MAINTENANCE - GAS - ME	Expense	Active
305729528940100	CONVERSION BURNER MAINTENANCE - ME	Expense	Active
300000008940200	MAINT OF RENTED CONV BURN - COMMON	Expense	Active
304080008940200	MAINT OF RENTED CONV BURN - NH	Expense	Active
304729538940200	NH EQUIP PROTECTION PLAN PTS & LBR	Expense	Active
305085008940200	MAINT OF RENTED CONV BURN - ME	Expense	Active
305729528940200	MAINT OF RENTED CONV BURN - ME	Expense	Active
304080009010000	CUSTOMER ACCOUNTS SUPVSN/EXP - NH	Expense	Active
305085009010000	CUSTOMER ACCOUNTS SUPVSN/EXP - ME	Expense	Active
300026009020000	CUST ACCTS METER READ EXP - COMMON	Expense	Active
304026009020000	CUST ACCTS METER READ EXP - NH	Expense	Active
304080009020000	CUST ACCTS METER READ EXP- NH	Expense	Active
305026009020000	CUST ACCTS METER READ EXP - ME	Expense	Active
305085009020000	CUST ACCTS METER READ EXP - ME	Expense	Active
300026009020200	METER READING - TELEPHONE EXPENSE - COMMON	Expense	Active
304026009020200	METER READING - TELEPHONE EXPENSE - NH	Expense	Active
305026009020200	METER READING - TELEPHONE EXPENSE - ME	Expense	Active
300026009020300	METER READING - PAYROLL EXPENSE - COMMON	Expense	Active
304026009020300	METER READING - PAYROLL EXPENSE - NH	Expense	Active
304080009020300	METER READING - PAYROLL EXPENSE - NH	Expense	Active
305026009020300	METER READING - PAYROLL EXPENSE - ME	Expense	Active
305085009020300	METER READING - PAYROLL EXPENSE - ME	Expense	Active
300026009020400	METER READING - TRAVEL EXPENSE - COMMON	Expense	Active
304026009020400	METER READING - TRAVEL EXPENSE - NH	Expense	Active
304080009020400	METER READING - TRAVEL EXPENSE - NH	Expense	Active

Account Code	Description	Type	Status
305026009020400	METER READING - TRAVEL EXPENSE - ME	Expense	Active
305085009020400	METER READING - TRAVEL EXPENSE - ME	Expense	Active
300026009020500	METER READING - UNIFORMS EXPENSE - COMMON	Expense	Active
304026009020500	METER READING - UNIFORMS EXPENSE - NH	Expense	Active
304080009020500	METER READING - UNIFORMS EXPENSE - NH	Expense	Active
305026009020500	METER READING - UNIFORMS EXPENSE - ME	Expense	Active
305085009020500	METER READING - UNIFORMS EXPENSE - ME	Expense	Active
300026009020600	METER READING - SUPPLIES EXPENSE - COMMON	Expense	Active
304026009020600	METER READING - SUPPLIES EXPENSE - NH	Expense	Active
304080009020600	METER READING - SUPPLIES EXPENSE - NH	Expense	Active
305026009020600	METER READING - SUPPLIES EXPENSE - ME	Expense	Active
305085009020600	METER READING - SUPPLIES EXPENSE - ME	Expense	Active
300026009020700	METER READING EXP-ADMIN EXP - COMMON	Expense	Active
304026009020700	METER READING EXP-ADMIN EXP - NH	Expense	Active
304080009020700	METER READING EXP-ADMIN EXP - NH	Expense	Active
305026009020700	METER READING EXP-ADMIN EXP - ME	Expense	Active
305085009020700	METER READING EXP-ADMIN EXP - ME	Expense	Active
300026009020800	METER READING-C/S READ IN/OUTS - COMMON	Expense	Active
304026009020800	METER READING-C/S READ IN/OUTS - NH	Expense	Active
304080009020800	METER READING-C/S READ IN/OUTS - NH	Expense	Active
305026009020800	METER READING-C/S READ IN/OUTS - ME	Expense	Active
305085009020800	METER READING-C/S READ IN/OUTS - ME	Expense	Active
300026009020900	METER READING-FLEET EXP - COMMON	Expense	Active
304026009020900	METER READING-FLEET EXP - NH	Expense	Active
304080009020900	METER READING-FLEET EXP - NH	Expense	Active
305026009020900	METER READING-FLEET EXP - ME	Expense	Active
305085009020900	METER READING-FLEET EXP - ME	Expense	Active
300026009021000	METER READING-STOREROOM EXP - COMMON	Expense	Active
304026009021000	METER READING-STOREROOM EXP - NH	Expense	Active
304080009021000	METER READING-STOREROOM EXP - NH	Expense	Active
305026009021000	METER READING-STOREROOM EXP - ME	Expense	Active
305085009021000	METER READING-STOREROOM EXP - ME	Expense	Active
300026009021100	METER WORK-NON-PROD - COMMON	Expense	Active
304026009021100	METER WORK-NON-PROD - NH	Expense	Active
304080009021100	METER WORK-NON-PROD - NH	Expense	Active
305026009021100	METER WORK-NON-PROD - ME	Expense	Active
305085009021100	METER WORK-NON-PROD - ME	Expense	Active
304080009030000	CREDIT DISCONNECTION - NH	Expense	Active
305085009030000	CREDIT DISCONNECTION - ME	Expense	Active
304080009030100	OPER SUPP TRAINING - GAS - NH	Expense	Active
305085009030100	OPER SUPP TRAINING - GAS - ME	Expense	Active
305085009030101	TURN ON AFTER CREDIT	Expense	Active
300021009030200	BILLG/ACCT FORMS/SUPPLIES - COMMON	Expense	Active
304021009030200	BILLG/ACCT FORMS/SUPPLIES - NH	Expense	Active
305021009030200	BILLG/ACCT FORMS/SUPPLIES - ME	Expense	Active
304080009030300	CREDIT & COLLECTIONS/PYRL - NH	Expense	Active
305085009030300	CREDIT & COLLECTIONS/PYRL - ME	Expense	Active
300021009030400	POSTAGE - COMMON	Expense	Active
304021009030400	POSTAGE - NH	Expense	Active
305021009030400	POSTAGE - ME	Expense	Active
304080009030401	POSTAGE - LOCAL - NH	Expense	Active
305085009030401	POSTAGE - LOCAL - ME	Expense	Active
304080009030500	MISC CREDIT EXPENSES - NH	Expense	Active
305085009030500	MISC CREDIT EXPENSES - ME	Expense	Active
300021009030501	MISC COST OF COLLECTIONS - COMMON	Expense	Active
304021009030501	MISC COST OF COLLECTIONS - NH	Expense	Active
305021009030501	MISC COST OF COLLECTIONS - ME	Expense	Active
300021009030502	COST OF COLLECTIONS - COMMON	Expense	Active
304021009030502	COST OF COLLECTIONS - NH	Expense	Active
305021009030502	COST OF COLLECTIONS - ME	Expense	Active
300021009030503	SUNDRY COST OF COLLECTIONS - COMMON	Expense	Active
304021009030503	SUNDRY COST OF COLLECTIONS - NH	Expense	Active
305021009030503	SUNDRY COST OF COLLECTIONS - ME	Expense	Active
300021009030504	O/S VENDOR SERVICES - MAILROOM - COMMON	Expense	Active

Account Code	Description	Type	Status
304021009030504	O/S VENDOR SERVICES - MAILROOM - NH	Expense	Active
305021009030504	O/S VENDOR SERVICES - MAILROOM - ME	Expense	Active
300010009030600	USC - CUSTOMER ACCOUNTING - COMMON	Expense	Active
300021009030600	USC - CUSTOMER ACCOUNTING - COMMON	Expense	Active
304010009030600	USC - CUSTOMER ACCOUNTING	Expense	Active
304021009030600	USC - CUSTOMER ACCOUNTING - NH	Expense	Active
305010009030600	USC - CUSTOMER ACCOUNTING - COMMON	Expense	Active
305021009030600	USC - CUSTOMER ACCOUNTING - ME	Expense	Active
300010009030601	USC - CUSTOMER ACCOUNTING - CAP	Expense	Active
304010009030601	USC - CUSTOMER ACCOUNTING - CAP	Expense	Active
305010009030601	USC - CUSTOMER ACCOUNTING - CAP	Expense	Active
300021009030800	MISC CUSTOMER RELATIONS - COMMON	Expense	Active
304021009030800	MISC CUSTOMER RELATIONS - NH	Expense	Active
305021009030800	MISC CUSTOMER RELATIONS - ME	Expense	Active
300021009031000	O/S REMITTANCE LOCK BOX	Expense	Active
304021009031000	O/S REMITTANCE LOCK BOX	Expense	Active
305021009031000	O/S REMITTANCE LOCK BOX	Expense	Active
304010009040000	PROVISION FOR DOUBTFUL ACCTS - DISTR - NH	Expense	Active
304021009040000	PROVISION FOR DOUBTFUL ACCTS - DISTR - NH	Expense	Active
305010009040000	PROVISION FOR DOUBTFUL ACCTS - DISTR - ME	Expense	Active
305021009040000	PROVISION FOR DOUBTFUL ACCTS - DISTR - ME	Expense	Active
304021009040001	PROVISION FOR DOUBTFUL ACCTS WIN- DISTR - NH	Expense	Active
304921149040001	PROVISION FOR DOUBTFUL ACCTS - CGA	Expense	Active
305021009040001	PROVISION FOR DOUBTFUL ACCTS WIN- DISTR - ME	Expense	Active
305921189040001	PROVISION FOR DOUBTFUL ACCTS - CGA	Expense	Active
304021009040002	PROVISION FOR DOUBTFUL ACCTS SUM- DISTR - NH	Expense	Active
304921449040002	PROVISION FOR DOUBTFUL ACCTS - CGA	Expense	Active
305021009040002	PROVISION FOR DOUBTFUL ACCTS SUM- DISTR - ME	Expense	Active
305921489040002	PROVISION FOR DOUBTFUL ACCTS - CGA	Expense	Active
304010009040027	PROVISION FOR DOUBTFUL ACCTS - NON-DIST - NH	Expense	Active
305010009040027	PROVISION FOR DOUBTFUL ACCTS - NON-DIST - ME	Expense	Active
304010149040099	BAD DEBT ALLOWANCE - PEAK - NH	Expense	Active
304010449040099	BAD DEBT ALLOWANCE - OFF PEAK - NH	Expense	Active
304910149040099	BAD DEBT ALLOWANCE - PEAK - NH	Expense	Active
304910449040099	BAD DEBT ALLOWANCE - OFF PEAK - NH	Expense	Active
305010189040099	BAD DEBT ALLOWANCE - PEAK - ME	Expense	Active
305010489040099	BAD DEBT ALLOWANCE - OFF PEAK - ME	Expense	Active
305910189040099	BAD DEBT ALLOWANCE - PEAK - ME	Expense	Active
305910489040099	BAD DEBT ALLOWANCE - OFF PEAK - ME	Expense	Active
304021009040100	PROVISION FOR DOUBTFUL ACCTS - SUNDRY - NH	Expense	Active
304921149040100	PROVISION FOR DOUBTFUL ACCTS - CGA - NH - PEAK	Expense	Active
304921449040100	PROVISION FOR DOUBTFUL ACCTS - CGA - NH - OFF PEAK	Expense	Active
305021009040100	PROVISION FOR DOUBTFUL ACCTS - SUNDRY - ME	Expense	Active
305921189040100	PROVISION FOR DOUBTFUL ACCTS - CGA - ME - PEAK	Expense	Active
305921489040100	PROVISION FOR DOUBTFUL ACCTS - CGA - ME - OFF PEAK	Expense	Active
304010009041000	BAD DEBT PURCH ACCT-NH	Expense	Active
305010009041000	BAD DEBT PURCH ACCT-NH	Expense	Active
304080009070000	CUSTMR SERVICE & INFO SUPRVN - NH	Expense	Active
305085009070000	CUSTMR SERVICE & INFO SUPRVN - ME	Expense	Active
304002009080000	CORPORATE SERVICES	Expense	Active
305002009080000	CORPORATE SERVICES	Expense	Active
304902729080050	DSM REG & GEN - MA/NH GAS	Expense	Active
305002739080051	UNREG EE PLAN & MGMT-ME	Expense	Active
304902729080060	EE OPS GEN ADMIN - MA/NH GAS	Expense	Active
305002739080061	UNREG EE INT OPERATIONS-ME	Expense	Active
304902729080070	DSM GEN M&E - MA/NH GAS	Expense	Active
305002739080071	UNREG EE INT M&E-ME	Expense	Active
304902729080080	EE GEN INTERNAL MKTING-GAS	Expense	Active
305002739080081	UNREG EE INTERNAL MKTING-ME	Expense	Active
304902729080090	EE GEN 3RD PTY MKTING-GAS	Expense	Active
305002739080091	UNREG EE 3RD PTY MKTING-ME	Expense	Active
304902729080095	EE 3RD PTY ADMIN- MA/NH GAS	Expense	Active
305002739080096	UNREG EE 3RD PTY ADMIN ME	Expense	Active
304080009080100	CUSTOMER SERVICE/PAYRL - NH	Expense	Active

Account Code	Description	Type	Status
304902729080100	GAS LOWINC DESIGN	Expense	Active
305002739080100	UNREG GASLOWINC PLAN&MGMT-ME	Expense	Active
305085009080100	CUSTOMER SERVICE/PAYRL - ME	Expense	Active
304902729080101	GAS LOWINC 3RD PTY DESIGN	Expense	Active
304902729080110	GAS LOWINC PROG ADMIN	Expense	Active
305002739080110	UNREG GASLOWINC INT OPS-ME	Expense	Active
304902729080111	GAS LOWINC ENGINEER SVCS	Expense	Active
305002739080111	UNREG GASLOWINC INT ENGSVCS-ME	Expense	Active
304902729080112	GAS LOWINC ADMIN MATERIALS	Expense	Active
305002739080112	UNREG GASLOWINC INT MATERIALS-ME	Expense	Active
304902729080113	GAS LOWINC REG & GENERAL	Expense	Active
304902729080114	GAS LOWINC 3RD PTY ADMIN	Expense	Active
305002739080114	UNREG GASLOWINC 3PTY OPS-ME	Expense	Active
304902729080120	GAS LOWINC MARKETING	Expense	Active
305002739080120	UNREG GASLOWINC INT MKTING-ME	Expense	Active
304902729080121	GAS LOWINC 3RD PTY MKTING	Expense	Active
305002739080121	UNREG GASLOWINC 3PTY MKT-ME	Expense	Active
304902729080130	GAS LOWINC M&E	Expense	Active
305002739080130	UNREG GASLOWINC M&E-ME	Expense	Active
304902729080131	GAS LOWINC 3RD PTY M&E	Expense	Active
305002739080131	UNREG GASLOWINC 3PTY M&E-ME	Expense	Active
304902729080140	GAS LOWINC CUST/CONTR REBATES	Expense	Active
305002739080140	UNREG GASLOWINC REBATES-ME	Expense	Active
304902729080141	GAS LOWINC ENERGY AUDITS	Expense	Active
305002739080141	UNREG GASLOWINC AUDITS-ME	Expense	Active
304080009080200	CUSTOMER SERVICE/MISC - NH	Expense	Active
305085009080200	CUSTOMER SERVICE/MISC - ME	Expense	Active
304902729082500	R GASWXN DESG - NH	Expense	Active
305002739082500	UNREG RESGASWXN PLAN&MGMT	Expense	Active
304902729082501	R GASWXN 3RDPTY DESG - NH	Expense	Active
304902729082510	R GASWXN PROGADMIN - NH	Expense	Active
305002739082510	UNREG RESGASWXN INTOPS-ME	Expense	Active
304902729082511	R GASWXN ENGSVCS - NH	Expense	Active
304902729082512	R GASWXN ADMMATS - NH	Expense	Active
304902729082513	R GASWXB R&G - NH	Expense	Active
304902729082514	R GASWXN 3PTY ADMIN - NH	Expense	Active
304902729082520	R GASWXN MKTING - NH	Expense	Active
305002739082520	UNREG RESGASWXN INTMKTING-ME	Expense	Active
304902729082521	R GASWXN 3PTY MKTING - NH	Expense	Active
304902729082530	R GASWXN M&E - NH	Expense	Active
304902729082531	R GASWXN 3RDPTY M&E - NH	Expense	Active
304902729082540	R GASWXN REBATES - NH	Expense	Active
304902729082541	R GASWXN AUDITS - NH	Expense	Active
304902729082700	GAS RCS DESIGN-NH	Expense	Active
304902729082701	GAS RCS 3RD PTY DESIGN-NH	Expense	Active
304902729082710	GAS RCS PROG ADMIN-NH	Expense	Active
304902729082711	GAS RCS ENGINEER SVCS-NH	Expense	Active
304902729082712	GAS RCS ADMIN MATS-NH	Expense	Active
304902729082713	GAS RCS REG & GENERAL-NH	Expense	Active
304902729082714	GAS RCS 3RD PTY ADMIN	Expense	Active
304902729082720	GAS RCS MARKETING-NH	Expense	Active
304902729082721	GAS RCS 3RD PTY MKTING	Expense	Active
304902729082730	GAS RCS M&E	Expense	Active
304902729082731	GAS RCS 3RD PTY M&E-NH	Expense	Active
304902729082740	GAS RCS REBATES-NH	Expense	Active
304902729082741	GAS RCS ENERGY AUDITS-NH	Expense	Active
304902729082900	R GASNETWKS DESIGN	Expense	Active
304902729082901	R GASNETWKS 3RD PTY DESIGN	Expense	Active
304902729082910	R GASNETWKS PROG ADMIN	Expense	Active
304902729082911	R GASNETWKS ENGINEER SVCS	Expense	Active
304902729082912	R GASNETWKS ADMIN MATS	Expense	Active
304902729082913	R GASNETWKS REG & GENERAL	Expense	Active
304902729082914	R GASNETWKS 3RD PTY ADMIN	Expense	Active
304902729082920	R GASNETWKS MARKETING	Expense	Active

Account Code	Description	Type	Status
304902729082921	R GASNETWKS 3RD PTY MKTING	Expense	Active
304902729082930	R GASNETWKS M&E	Expense	Active
304902729082931	R GASNETWKS 3RD PTY M&E	Expense	Active
304902729082940	R GASNETWKS REBATES	Expense	Active
304902729082941	R GASNETWKS ENERGY AUDITS	Expense	Active
304902729083600	LG GAS CUSTOM DESIGN	Expense	Active
305002739083600	UNREG LG GASCUST PLAN/MGMT-ME	Expense	Active
304902729083601	LG GAS CUSTOM 3RD PTY DESIGN	Expense	Active
304902729083610	LG GAS CUSTOM PROG ADMIN	Expense	Active
305002739083610	UNREG LG GASCUST INT OPS-ME	Expense	Active
304902729083611	LG GAS CUSTOM ENGINEER SVCS	Expense	Active
305002739083611	UNREG LG GASCUST INT ENGSVCS-ME	Expense	Active
304902729083612	LG GAS CUSTOM ADMIN MAT.	Expense	Active
305002739083612	UNREG LG GASCUST INT MTLS-ME	Expense	Active
304902729083613	LG GAS CUSTOM REG & GENERAL	Expense	Active
305002739083613	UNREG LG GASCUST INT OPS ELECTRIC-ME	Expense	Active
304902729083614	LG GAS CUSTOM 3RD PTY ADMIN	Expense	Active
305002739083614	UNREG LG GASCUST 3RDPTY OPS-ME	Expense	Active
304902729083620	LG GAS CUSTOM MARKETING	Expense	Active
305002739083620	UNREG LG GASCUST INT MKTING-ME	Expense	Active
304902729083621	LG GAS CUSTOM 3RD PTY MKTING	Expense	Active
304902729083630	LG GAS CUSTOM M&E	Expense	Active
305002739083630	UNREG LG GASCUST INT M&E-ME	Expense	Active
304902729083631	LG GAS CUSTOM 3RD PTY M&E	Expense	Active
305002739083631	UNREG LG GASCUST 3RDPTY M&E-ME	Expense	Active
304902729083640	LG GAS CUSTOM REBATES	Expense	Active
305002739083640	UNREG LG GASCUST REBATES-ME	Expense	Active
304902729083641	LG GAS CUSTOM ENERGY AUDITS	Expense	Active
305002739083641	UNREG LG GASCUST AUDITS-ME	Expense	Active
304902729084700	ES HOMES DESIGN	Expense	Active
304902729084701	ES HOMES 3RD PTY DESIGN -NH	Expense	Active
304902729084710	ES HOMES PROG ADMIN - NH	Expense	Active
304902729084711	ES HOMES ENGINEER SVCS - NH	Expense	Active
304902729084712	ES HOMES ADMIN MATERIALS	Expense	Active
304902729084713	ES HOMES REG & GENERAL	Expense	Active
304902729084714	ES HOMES 3RD PTY ADMIN	Expense	Active
304902729084720	ES HOMES MARKETING	Expense	Active
304902729084721	ES HOMES 3RD PTY MKTING	Expense	Active
304902729084730	ES HOMES M&E	Expense	Active
304902729084731	ES HOMES 3RD PTY M&E	Expense	Active
304902729084740	ES HOMES CUST/CONTR REBATES	Expense	Active
304902729084741	ES HOMES ENERGY AUDITS	Expense	Active
304902729084900	SCI GASCUST DESG	Expense	Active
305002739084900	UNREG SCI GASCUST PLAN/MGMT-ME	Expense	Active
304902729084901	SCI GASCUST 3PTYDESG	Expense	Active
304902729084910	SCI GASCUST PROGADM	Expense	Active
305002739084910	UNREG SCI GASCUST INT OPS-ME	Expense	Active
304902729084911	SCI GASCUST ENGSVCS	Expense	Active
305002739084911	UNREG SCI GASCUST ENGSVCS-ME	Expense	Active
304902729084912	SCI GASCUST ADMMAT	Expense	Active
305002739084912	UNREG SCI GASCUST MATERIALS-ME	Expense	Active
304902729084913	SCI GASCUST R&G	Expense	Active
305002739084913	UNREG SCI GASCUST ELECTRIC-ME	Expense	Active
304902729084914	SCI GASCUST 3PTYADM	Expense	Active
305002739084914	UNREG SCI GAS 3RD PTY OPS-ME	Expense	Active
304902729084920	SCI GASCUST MKTING	Expense	Active
305002739084920	UNREG SCI GASCUST INT MKT-ME	Expense	Active
304902729084921	SCI GASCUST 3PTYMKT	Expense	Active
305002739084921	UNREG SCI GASCUST 3PTY MKT-ME	Expense	Active
304902729084930	SCI GASCUST M&E	Expense	Active
305002739084930	UNREG SCI GASCUST INT M&E-ME	Expense	Active
304902729084931	SCI GASCUST 3PTYM&E	Expense	Active
305002739084931	UNREG SCI GASCUST 3RD PYT M&E-ME	Expense	Active
304902729084940	SCI GASCUST REBATES	Expense	Active

Account Code	Description	Type	Status
305002739084940	UNREG SCI GASCUST REBATES-ME	Expense	Active
304902729084941	SCI GASCUST AUDITS	Expense	Active
305002739084941	UNREG SCI GASCUST AUDITS-ME	Expense	Active
304902729085000	CI GASNETWKS DSGN	Expense	Active
305002739085000	UNREG CI GASNTWKS PLAN/MGMT-ME	Expense	Active
304902729085001	CI GASNW 3PTYDSGN	Expense	Active
304902729085010	CI GASNETWKS PROGADM	Expense	Active
305002739085010	UNREG CI GASNTWKS INT OPS-ME	Expense	Active
304902729085011	CI GASNETWKS ENGSVCS	Expense	Active
305002739085011	UNREG CI GASNTWKS INT ENGSVCS-ME	Expense	Active
304902729085012	CI GASNETWKS ADMMATS	Expense	Active
304902729085013	CI GASNETWKS R&G	Expense	Active
305002739085013	UNREG CI GASNTWKS ELECTRIC-ME	Expense	Active
304902729085014	CI GASNETWKS 3PTY ADM	Expense	Active
305002739085014	UNREG CI GASNTWKS 3RDPTY OPS-ME	Expense	Active
304902729085020	CI GASNETWKS MKTING	Expense	Active
305002739085020	UNREG CI GASNTWKS INT MKT-ME	Expense	Active
304902729085021	CI GASNETWKS 3PTYMKT	Expense	Active
305002739085021	UNREG CI GASNTWKS 3PTY MKT-ME	Expense	Active
304902729085030	CI GASNETWKS M&E	Expense	Active
305002739085030	UNREG CI GASNTWKS INT M&E-ME	Expense	Active
304902729085031	CI GASNETWKS 3PTYM&E	Expense	Active
305002739085031	UNREG CI GASNTWKS 3RD PTY M&E-ME	Expense	Active
304902729085040	CI GASNETWKS REBATES	Expense	Active
305002739085040	UNREG CI GASNTWKS REBATES-ME	Expense	Active
304902729085041	CI GASNETWKS AUDITS	Expense	Active
305002739085041	UNREG CI GASNTWKS AUDITS-ME	Expense	Active
304902729085700	C&I MF (COM AREA) DESIGN	Expense	Active
305002739085700	UNREG MULTIFAM PLAN/MGMT-ME	Expense	Active
304902729085701	C&I MF (COM AREA) 3RD PTY DESIGN	Expense	Active
304902729085710	C&I MF (COM AREA) PROG ADMIN	Expense	Active
305002739085710	UNREG MULTIFAM INT OPS-ME	Expense	Active
304902729085711	C&I MF (COM AREA) ENGINEER SVCS	Expense	Active
305002739085711	UNREG MULTIFAM ENGSVCS-ME	Expense	Active
304902729085712	C&I MF (COM AREA) ADMIN MATERIALS	Expense	Active
305002739085712	UNREG MULTIFAM MTRLS-ME	Expense	Active
304902729085713	C&I MF (COM AREA) REG & GENERAL	Expense	Active
305002739085713	UNREG MULTIFAM ELECTRIC-ME	Expense	Active
304902729085714	C&I MF (COM AREA) 3RD PTY ADMIN	Expense	Active
305002739085714	UNREG MULTIFAM 3RDPTY OPS-ME	Expense	Active
304902729085720	C&I MF (COM AREA) MARKETING	Expense	Active
305002739085720	UNREG MULTIFAM INT MKT-ME	Expense	Active
304902729085721	C&I MF (COM AREA) 3RD PTY MKTING	Expense	Active
305002739085721	UNREG MULTIFAM 3PTY MKT-ME	Expense	Active
304902729085730	C&I MF (COM AREA) M&E	Expense	Active
305002739085730	UNREG MULTIFAM INT M&E-ME	Expense	Active
304902729085731	C&I MF (COM AREA) 3RD PTY M&E	Expense	Active
305002739085731	UNREG MULTIFAM 3PTY M&E-ME	Expense	Active
304902729085740	C&I MF (COM AREA) REBATES	Expense	Active
305002739085740	UNREG MULTIFAM REBATES-ME	Expense	Active
304902729085741	C&I MF (COM AREA) AUDITS	Expense	Active
305002739085741	UNREG MULTIFAM AUDITS-ME	Expense	Active
304902729085800	R SELF-INSTALL DESIGN	Expense	Active
304902729085801	R SELF-INSTALL 3PTYDSGN	Expense	Active
304902729085810	R SELF-INSTALL PROGADM	Expense	Active
304902729085811	R SELF-INSTALL ENGSVCS	Expense	Active
304902729085812	R SELF-INSTALL ADMMATS	Expense	Active
304902729085813	R SELF-INSTALL REG & GEN	Expense	Active
304902729085814	R SELF-INSTALL 3PTY ADM	Expense	Active
304902729085820	R SELF-INSTALL MKTING	Expense	Active
304902729085821	R SELF-INSTALL 3PTYMKTING	Expense	Active
304902729085830	R SELF-INSTALL M&E	Expense	Active
304902729085831	R SELF-INSTALL 3PTYM&E	Expense	Active
304902729085840	R SELF-INSTALL REBATES	Expense	Active

Account Code	Description	Type	Status
304902729085841	R SELF-INSTALL AUDITS	Expense	Active
304002009087900	SERVICE CORP ACTUAL	Expense	Active
305002009087900	SERVICE CORP ACTUAL	Expense	Active
304021009090100	NEIGHBOR HELPING NEIGHBOR	Expense	Active
304002009100000	CORPORATE SERVICES	Expense	Active
305002009100000	CORPORATE SERVICES	Expense	Active
300002009110000	SUPERVISION - COMMON	Expense	Active
304002009110000	SUPERVISION - NH	Expense	Active
304080009110000	SUPERVISION - NH	Expense	Active
305002009110000	SUPERVISION - ME	Expense	Active
305085009110000	SUPERVISION - ME	Expense	Active
304002009117900	SERVICE CORP ACTUAL	Expense	Active
305002009117900	SERVICE CORP ACTUAL	Expense	Active
300002009120000	SELLING EXPENSE - COMMON	Expense	Active
304002009120000	SELLING EXPENSE - NH	Expense	Active
304080009120000	SELLING EXPENSE - NH	Expense	Active
305002009120000	SELLING EXPENSE - ME	Expense	Active
305085009120000	SELLING EXPENSE - ME	Expense	Active
304002009127900	SERVICE CORP ACTUAL	Expense	Active
305002009127900	SERVICE CORP ACTUAL	Expense	Active
304080009130000	ADVERTISING EXPENSE - NH	Expense	Active
305085009130000	ADVERTISING EXPENSE - ME	Expense	Active
304002009137900	SERVICE CORP ACTUAL	Expense	Active
305002009137900	SERVICE CORP ACTUAL	Expense	Active
304080009160000	MISC SALES EXPENSE - NH	Expense	Active
305085009160000	MISC SALES EXPENSE - ME	Expense	Active
300070009200000	A&G SALARIES-COMMON	Expense	Active
304070009200000	A&G SALARIES - NH	Expense	Active
304080009200000	A&G SALARIES-NH	Expense	Active
305070009200000	A&G SALARIES - ME	Expense	Active
305085009200000	A&G SALARIES-ME	Expense	Active
300003009200500	INCENTIVE COMPENSATION	Expense	Active
300010009200500	INCENTIVE COMPENSATION CAPITALIZED	Expense	Active
304003009200500	INCENTIVE COMPENSATION - NH	Expense	Active
304010009200500	INCENTIVE COMPENSATION CAPITALIZED	Expense	Active
304080009200500	OPER SUPP - ADMIN TRAINING - GAS - NH	Expense	Active
305003009200500	INCENTIVE COMPENSATION - ME	Expense	Active
305010009200500	INCENTIVE COMPENSATION CAPITALIZED	Expense	Active
305085009200500	OPER SUPP - ADMIN TRAINING - GAS - ME	Expense	Active
304080009210100	GEN OFFICE SUPPLIES & EXP - NH	Expense	Active
305085009210100	GEN OFFICE SUPPLIES & EXP - ME	Expense	Active
300008009210108	BANK FEES & COMMITMENT FEES - COMMON	Expense	Active
304008009210108	BANK FEES & COMMITMENT FEES - NH	Expense	Active
305008009210108	BANK FEES & COMMITMENT FEES - ME	Expense	Active
300008009210109	Credit Card Fees - COMMON	Expense	Active
300021009210109	CREDIT CARD FEES	Expense	Active
304008009210109	Credit Card Fees - NH	Expense	Active
304021009210109	CREDIT CARD FEES	Expense	Active
305008009210109	Credit Card Fees - ME	Expense	Active
305021009210109	CREDIT CARD FEES	Expense	Active
304080009210120	UNALLOWABLE MEALS EXP - NH	Expense	Active
305085009210120	UNALLOWABLE MEALS EXP - ME	Expense	Active
304080009210200	TRAVEL & MEALS EXP - NH	Expense	Active
305085009210200	TRAVEL & MEALS EXP - ME	Expense	Active
300013009210300	DUES & SUBSCRIPTIONS - COMMON	Expense	Active
304013009210300	DUES & SUBSCRIPTIONS - NH	Expense	Active
305013009210300	DUES & SUBSCRIPTIONS - ME	Expense	Active
304010009211500	SVC CENTER CAPITALIZED- NH	Expense	Active
304080009211500	SERVICE CENTER CAPITALIZED - NH	Expense	Active
305010009211500	SVC CENTER CAPITALIZED- ME	Expense	Active
305085009211500	SERVICE CENTER CAPITALIZED - ME	Expense	Active
304080009211600	SERVICE CENTER EXPENSED - NH	Expense	Active
305085009211600	SERVICE CENTER EXPENSED - ME	Expense	Active
304009009211700	Telephone Services - Service Center - NH	Expense	Active

Account Code	Description	Type	Status
304080009211700	Telephone Services - Service Center - NH	Expense	Active
305009009211700	Telephone Services - Service Center - ME	Expense	Active
305085009211700	Telephone Services - Service Center - ME	Expense	Active
304080009211800	Telephone Services - All Others - NH	Expense	Active
305085009211800	Telephone Services - All Others - ME	Expense	Active
304010009211900	TELEPHONE SERVICES CAPITALIZED- NH	Expense	Active
304080009211900	TELEPHONE SERVICES CAPITALIZED	Expense	Active
305010009211900	TELEPHONE SERVICES CAPITALIZED- ME	Expense	Active
305085009211900	TELEPHONE SERVICES CAPITALIZED	Expense	Active
300013009213800	PC SOFTWARE & SUPPLY - COMMON	Expense	Active
304013009213800	PC SOFTWARE & SUPPLY - NH	Expense	Active
305013009213800	PC SOFTWARE & SUPPLY - ME	Expense	Active
304010009213900	LDAC UNBILLED - NH	Expense	Active
305010009213900	LDAC UNBILLED - ME	Expense	Active
304010009220000	ADMINISTRATIVE EXPENSES TRANSFERRED - NH	Expense	Active
304080009220000	ADMINISTRATIVE EXPENSES TRANSFERRED - NH	Expense	Active
305010009220000	ADMINISTRATIVE EXPENSES TRANSFERRED - ME	Expense	Active
305085009220000	ADMINISTRATIVE EXPENSES TRANSFERRED - ME	Expense	Active
300003009220100	FRINGE BENEFITS - COMMON	Expense	Active
304003009220100	FRINGE BENEFITS - NH	Expense	Active
305003009220100	FRINGE BENEFITS - ME	Expense	Active
300010009230000	OS-LEGAL- ACCOUNTING-COMMON	Expense	Active
300012009230000	OS LEGAL - ENGINEERING-COMMON	Expense	Active
304012009230000	OS LEGAL - ENGINEERING-NH	Expense	Active
304080009230000	OS LEGAL - LOCAL-NH-DOC-ONLY	Expense	Active
304901779230000	NH LIEAP COSTS	Expense	Active
305012009230000	OS LEGAL - ENGINEERING-ME	Expense	Active
305085009230000	OS LEGAL - LOCAL-ME-DOC-ONLY	Expense	Active
300008009230001	OS LEGAL - CORP-COMMON	Expense	Active
304008009230001	OS LEGAL - CORP-NH	Expense	Active
305008009230001	OS LEGAL - CORP-ME	Expense	Active
300001009230002	OS LEGAL - MISC	Expense	Active
300013009230002	OS LEGAL - MISC - COMMON	Expense	Active
304001009230002	OS LEGAL - MISC	Expense	Active
304013009230002	OS LEGAL - MISC	Expense	Active
305001009230002	OS LEGAL - MISC	Expense	Active
305013009230002	OS LEGAL - MISC-ME	Expense	Active
304802009230003	MKT DEV/PROJ MGMT - NH	Expense	Active
304829009230003	MKT DEV/PROJ MGMT - NH	Expense	Active
305802009230003	MKT DEV/PROJ MGMT - ME	Expense	Active
305829009230003	MKT DEV/PROJ MGMT - ME	Expense	Active
300001009230100	OS OTHER	Expense	Active
304001009230100	OS OTHER	Expense	Active
305001009230100	OS OTHER	Expense	Active
300010009230200	OUTSIDE SERVICES-AUDIT-COMMON	Expense	Active
300021009230200	MISC COSTS - AFCC-COMMON	Expense	Active
304010009230200	OUTSIDE SERVICES-AUDIT-NH	Expense	Active
304021009230200	MISC COSTS - AFCC-NH	Expense	Active
305010009230200	OUTSIDE SERVICES-AUDIT-ME	Expense	Active
305021009230200	MISC COSTS - AFCC-ME	Expense	Active
304010009230201	AUDIT FEES CAPITALIZED	Expense	Active
305010009230201	AUDIT FEES CAPITALIZED	Expense	Active
300010009230300	OS UNITIL SERVICE CORP-COMMON	Expense	Active
304010009230300	OS UNITIL SERVICE CORP-NH	Expense	Active
305010009230300	OS UNITIL SERVICE CORP-ME	Expense	Active
300010009230301	OS UNITIL SERVICE CORP-COMMON-CAP	Expense	Active
304010009230301	OS UNITIL SERVICE CORP-NH-CAP	Expense	Active
305010009230301	OS UNITIL SERVICE CORP-ME-CAP	Expense	Active
300010009230305	USC OUTSIDE SERVICES-DIRECT CHGS-COMMON	Expense	Active
304010009230305	USC OUTSIDE SERVICES-DIRECT CHGS-NH	Expense	Active
305010009230305	USC OUTSIDE SERVICES-DIRECT CHGS-ME	Expense	Active
300010009230306	OS USC - OTHER-COMMON	Expense	Active
304010009230306	OS- USC-OTHER-NH	Expense	Active
305010009230306	OS-USC - OTHER-ME	Expense	Active

Account Code	Description	Type	Status
300010009230307	DIRECT CHARGES CAPITALIZED	Expense	Active
304010009230307	DIRECT CHARGES CAPITALIZED	Expense	Active
305010009230307	DIRECT CHARGES CAPITALIZED	Expense	Active
300010009230308	USC ALLOCATED PBOP EXPENSE-COMMON	Expense	Active
304010009230308	USC ALLOCATED PBOP EXPENSE-NH	Expense	Active
305010009230308	USC ALLOCATED PBOP EXPENSE-ME	Expense	Active
300010009230310	USC ALLOCATED PENSION EXPENSE-COMMON	Expense	Active
304010009230310	USC ALLOCATED PENSION EXPENSE-NH	Expense	Active
305010009230310	USC ALLOCATED PENSION EXPENSE-ME	Expense	Active
300010009230400	OS OTHER	Expense	Active
300012009230400	OS - ENGINEERING - COMMON	Expense	Active
304010009230400	OS OTHER	Expense	Active
304012009230400	OS - ENGINEERING - NH	Expense	Active
305010009230400	OS OTHER	Expense	Active
305012009230400	OS - ENGINEERING - ME	Expense	Active
300010009230500	OS - AFFILIATE - COMMON	Expense	Active
304010009230500	OS - AFFILIATE - NH	Expense	Active
305010009230500	OS - AFFILIATE - ME	Expense	Active
300013009230600	OS IRP EXPENSE-COMMON	Expense	Active
304002509230600	USC - WATER HEATER PROGRAM (GAS)-NH	Expense	Active
304013009230600	OS IRP EXPENSE-NH	Expense	Active
304729509230600	USC EXPS - WATER HTR PROG - NH	Expense	Active
304729539230600	USC EXPS - EASY CARE - NH	Expense	Active
305002509230600	USC - WATER HEATER PROGRAM (GAS)-ME	Expense	Active
305013009230600	OS IRP EXPENSE-ME	Expense	Active
305729509230600	USC EXPS - WATER HTR PROG - ME	Expense	Active
300013009230700	OS GAS CONTRACTS EXPENSE OTHER-COMMON	Expense	Active
304013009230700	OS GAS CONTRACTS EXPENSE OTHER-NH	Expense	Active
305013009230700	OS GAS CONTRACTS EXPENSE OTHER-ME	Expense	Active
300021009230800	MISC COSTS - AFCC - COMMON	Expense	Active
304021009230800	MISC COSTS - AFCC-NH	Expense	Active
305021009230800	MISC COSTS - AFCC-ME	Expense	Active
300010009230900	OUTSIDE SERVICES-COMMON	Expense	Active
304010009230900	OUTSIDE SERVICES-NH	Expense	Active
304080009230900	OUTSIDE SERVICES-NH	Expense	Active
305010009230900	OUTSIDE SERVICES-ME	Expense	Active
305085009230900	OUTSIDE SERVICES-ME	Expense	Active
300002009231000	DSM IMPLEMENTATION EXP - COMMON	Expense	Active
300010009231000	OUTSIDE SERVICES - PRE ACQUISITION - COMMON	Expense	Active
304002009231000	DSM IMPLEMENTATION EXP - NH	Expense	Active
304010009231000	OUTSIDE SERVICES - PRE ACQUISITION - NH	Expense	Active
305002009231000	DSM IMPLEMENTATION EXP - ME	Expense	Active
305010009231000	OUTSIDE SERVICES - PRE ACQUISITION - ME	Expense	Active
300010009231100	OUTSIDE SERVICES - POST ACQUISITION	Expense	Active
304010009231100	OUTSIDE SERVICES - POST ACQUISITION	Expense	Active
305010009231100	OUTSIDE SERVICES - POST ACQUISITION	Expense	Active
300017009231500	OS-EMERGENCY MGMT & COMPLIANCE	Expense	Active
304017009231500	OS-EMERGENCY MGMT & COMPLIANCE	Expense	Active
305017009231500	OS-EMERGENCY MGMT & COMPLIANCE	Expense	Active
304002009233000	MKT DEV - GENERAL -NH	Expense	Active
304802009233000	MKT DEV - GENERAL- NH	Expense	Active
304829009233000	MKT DEV - GENERAL- NH	Expense	Active
305002009233000	MKT DEV - GENERAL -ME	Expense	Active
305802009233000	MKT DEV - GENERAL - ME	Expense	Active
305829009233000	MKT DEV - GENERAL - ME	Expense	Active
304802009233003	MKT INCENTIVES - LOW USE-NH	Expense	Active
304829009233003	MKT INCENTIVES - LOW USE-NH	Expense	Active
305802009233003	MKT INCENTIVES - LOW USE-ME	Expense	Active
305829009233003	MKT INCENTIVES - LOW USE-ME	Expense	Active
304802009233004	MKT INCENTIVES - IGS-NH	Expense	Active
304829009233004	MKT INCENTIVES - IGS-NH	Expense	Active
305802009233004	MKT INCENTIVES - IGS-ME	Expense	Active
305829009233004	MKT INCENTIVES - IGS-ME	Expense	Active
304802009233005	MKT INCENTIVES - OTM-NH	Expense	Active

Account Code	Description	Type	Status
304829009233005	MKT INCENTIVES - OTM-NH	Expense	Active
305802009233005	MKT INCENTIVES - OTM-ME	Expense	Active
305829009233005	MKT INCENTIVES - OTM-ME	Expense	Active
304802009233203	FIELD OPERATIONS/ACCOUNT MGMT-NH	Expense	Active
304829009233203	FIELD OPERATIONS/ACCOUNT MGMT-NH	Expense	Active
305802009233203	FIELD OPERATIONS/ACCOUNT MGMT-ME	Expense	Active
305829009233203	FIELD OPERATIONS/ACCOUNT MGMT-ME	Expense	Active
300008009240000	PROPERTY INSURANCE-COMMON	Expense	Active
304008009240000	PROPERTY INSURANCE-NH	Expense	Active
305008009240000	PROPERTY INSURANCE-ME	Expense	Active
300010009240001	PROPERTY INS CAPITALIZED-COMMON	Expense	Active
304010009240001	PROPERTY INS CAPITALIZED-NH	Expense	Active
305010009240001	PROPERTY INS CAPITALIZED-ME	Expense	Active
300008009250000	D & O AND FIDUCIARY-COMMON	Expense	Active
304008009250000	D & O AND FIDUCIARY-NH	Expense	Active
305008009250000	D & O AND FIDUCIARY-ME	Expense	Active
304080009250100	INJURIES & DAMAGES SAFETY - NH	Expense	Active
305085009250100	INJURIES & DAMAGES SAFETY - ME	Expense	Active
300008009250200	GENERAL LIABILITY-COMMON	Expense	Active
304008009250200	GENERAL LIABILITY-NH	Expense	Active
305008009250200	GENERAL LIABILITY-ME	Expense	Active
300010009250201	GENERAL LIAB CAPITALIZED-COMMON	Expense	Active
304010009250201	GEN LIAB CAPITALIZED-NH	Expense	Active
305010009250201	GEN LIAB CAPITALIZED-ME	Expense	Active
300008009250202	GENERAL LIABITY CLAIMS-COMMON	Expense	Active
304008009250202	GENERAL LIABITY CLAIMS-NH	Expense	Active
305008009250202	GENERAL LIABITY CLAIMS-ME	Expense	Active
300000009250300	INJ & DAM - ENVIRONMENTAL - COMMON	Expense	Active
304080009250300	INJ & DAM - ENVIRONMENTAL - NH	Expense	Active
305085009250300	INJ & DAM - ENVIRONMENTAL - ME	Expense	Active
300008009250400	WORKERS COMP EXP-COMMON	Expense	Active
304008009250400	WORKERS COMP EXP-NH	Expense	Active
305008009250400	WORKERS COMP EXP-ME	Expense	Active
300010009250401	WORKERS COMP CAPITALIZED-COMMON	Expense	Active
304010009250401	WORKERS COMP CAPITALIZED-NH	Expense	Active
305010009250401	WORKERS COMP CAPITALIZED-ME	Expense	Active
300008009250500	INSURANCE - OTHER	Expense	Active
304008009250500	INSURANCE - NH	Expense	Active
305008009250500	INSURANCE - ME	Expense	Active
300003009260000	EMPL PENSION-PAYROLL - COMMON	Expense	Active
304003009260000	EMPL PENSION-PAYROLL - NH	Expense	Active
305003009260000	EMPL PENSION-PAYROLL - ME	Expense	Active
300003009260100	EMPL PENSION-40 - NH(k) - COMMON	Expense	Active
304003009260100	EMPL PENSION-401k - NH	Expense	Active
305003009260100	EMPL PENSION-401k - ME	Expense	Active
300010009260101	401K CAPITALIZED - COMMON	Expense	Active
304010009260101	401K CAPITALIZED - NH	Expense	Active
305010009260101	401K CAPITALIZED - ME	Expense	Active
300003009260201	FASB 87 - PENSION	Expense	Active
304003009260201	FASB 87 - PENSION	Expense	Active
305003009260201	FASB 87 - PENSION	Expense	Active
300010009260205	FASB 87 - PENSION - REG ASSET RECLASS - COMMON	Expense	Active
304010009260205	FASB 87 - PENSION - REG ASSET RECLASS - NH	Expense	Active
305010009260205	FASB 87 - PENSION - REG ASSET RECLASS - ME	Expense	Active
300010009260210	FASB 87 - PENSION EXP - USC ALLOC	Expense	Active
304010009260210	FASB 87 - PENSION EXP - USC ALLOC	Expense	Active
305010009260210	FASB 87 - PENSION EXP - USC ALLOC	Expense	Active
300010009260211	FASB 87 - REG ASSET - USC ALLOC - COMMON	Expense	Active
304010009260211	FASB 87 - REG ASSET - USC ALLOC - NH	Expense	Active
305010009260211	FASB 87 - REG ASSET - USC ALLOC - ME	Expense	Active
304010009260299	FASB87 YEAR END ACCRUAL ADJ	Expense	Active
305010009260299	FASB87 YEAR END ACCRUAL ADJ	Expense	Active
300003009260300	HEALTH INSUR MEDICAL ONLY-COMMON	Expense	Active
304003009260300	HEALTH INSUR MEDICAL ONLY-NH	Expense	Active

Account Code	Description	Type	Status
305003009260300	HEALTH INSUR MEDICAL ONLY-ME	Expense	Active
300003009260301	HEALTH INS - EMP CONTR - MEDICAL ONLY-COMMON	Expense	Active
304003009260301	HEALTH INS - EMP CONTR - MEDICAL ONLY-NH	Expense	Active
305003009260301	HEALTH INS - EMP CONTR - MEDICAL ONLY-ME	Expense	Active
300010009260302	EMPLOYEE BENEFIT ACCRUAL ADJ-COMMON - COMMON	Expense	Active
304010009260302	EMPLOYEE BENEFIT ACCRUAL ADJ	Expense	Active
305010009260302	EMPLOYEE BENEFIT ACCRUAL ADJ	Expense	Active
304003009260303	HEALTH INS-DRUG SUBSIDY	Expense	Active
305003009260303	HEALTH INS-DRUG SUBSIDY	Expense	Active
300003009260400	EMPL BENEFIT-LIFE INSURANCE-COMMON	Expense	Active
304003009260400	EMPL BENEFIT-LIFE INSURANCE-NH	Expense	Active
305003009260400	EMPL BENEFIT-LIFE INSURANCE-ME	Expense	Active
300010009260500	BENEFIT COST CAPITALIZED - COMMON	Expense	Active
304010009260500	BENEFIT COST CAPITALIZED - NH	Expense	Active
305010009260500	BENEFIT COST CAPITALIZED - ME	Expense	Active
300003009260600	EMPL BENEFITS OTHER-USC - COMMON	Expense	Active
304003009260600	EMPL BENEFITS OTHER-USC - NH	Expense	Active
304010009260600	EMPL BENEFITS OTHER	Expense	Active
305003009260600	EMPL BENEFITS OTHER-USC - ME	Expense	Active
305010009260600	EMPL BENEFITS OTHER	Expense	Active
300010009260800	PENSION COST CAPITALIZED - COMMON	Expense	Active
304010009260800	PENSION COST CAPITALIZED	Expense	Active
305010009260800	PENSION COST CAPITALIZED	Expense	Active
304010009260812	PENSION COST CAPITALIZED - USC ALLOC	Expense	Active
305010009260812	PENSION COST CAPITALIZED - USC ALLOC	Expense	Active
300003009260900	SFAS 106- PBOP EXPENSE	Expense	Active
304003009260900	SFAS 106- PBOP EXPENSE	Expense	Active
305003009260900	SFAS 106- PBOP EXPENSE	Expense	Active
300010009260901	SFAS 106 - PBOP - REG ASSET RECLASS	Expense	Active
304010009260901	SFAS 106 - PBOP - REG ASSET RECLASS	Expense	Active
305010009260901	SFAS 106 - PBOP - REG ASSET RECLASS	Expense	Active
300010009260910	SFAS 106- PBOP EXPENSE - USC ALLOC	Expense	Active
304010009260910	SFAS 106- PBOP EXPENSE - USC ALLOC	Expense	Active
305010009260910	SFAS 106- PBOP EXPENSE - USC ALLOC	Expense	Active
300010009260911	SFAS 106 - PBOP - REG ASSET -USC ALLOC - COMMON	Expense	Active
304010009260911	SFAS 106 - PBOP - REG ASSET -USC ALLOC - NH	Expense	Active
305010009260911	SFAS 106 - PBOP - REG ASSET -USC ALLOC - ME	Expense	Active
304010009260999	SFAS106 YEAR END ACCRUAL ADJ	Expense	Active
305010009260999	SFAS106 YEAR END ACCRUAL ADJ	Expense	Active
300003009261000	EMPL PENSION FUND SERVICES	Expense	Active
304003009261000	EMPL PENSION FUND SERVICES - NH	Expense	Active
305003009261000	EMPL PENSION FUND SERVICES - ME	Expense	Active
300003009261100	MISC GENERAL EXPENSE	Expense	Active
304003009261100	MISC GENERAL EXPENSE - NH	Expense	Active
304010009261100	MISC GENERAL EXPENSE	Expense	Active
305003009261100	MISC GENERAL EXPENSE - ME	Expense	Active
305010009261100	MISC GENERAL EXPENSE	Expense	Active
300003009261200	DENTAL INSURANCE-COMMON	Expense	Active
304003009261200	DENTAL INSURANCE-NH	Expense	Active
305003009261200	DENTAL INSURANCE-ME	Expense	Active
300003009261201	DENTAL INSURANCE - EMP CONTRIBUTION-COMMON	Expense	Active
304003009261201	DENTAL INSURANCE - EMP CONTRIBUTION-NH	Expense	Active
305003009261201	DENTAL INSURANCE - EMP CONTRIBUTION-ME	Expense	Active
300003009261300	AD&D INSURANCE-COMMON	Expense	Active
304003009261300	AD&D INSURANCE-NH	Expense	Active
305003009261300	AD&D INSURANCE-ME	Expense	Active
300003009261400	LTD INSURANCE-COMMON	Expense	Active
304003009261400	LTD INSURANCE - NH	Expense	Active
305003009261400	LTD INSURANCE	Expense	Active
300003009261500	RETIREE LIFE INSURANCE-COMMON	Expense	Active
304003009261500	RETIREE LIFE INSURANCE-NH	Expense	Active
305003009261500	RETIREE LIFE INSURANCE-ME	Expense	Active
300010009261700	PBOP COST CAPITALIZED - COMMON	Expense	Active
304010009261700	PBOP COST CAPITALIZED - NH	Expense	Active

Account Code	Description	Type	Status
305010009261700	PBOP COST CAPITALIZED - ME	Expense	Active
304010009261712	PBOP COST CAPITALIZED - USC ALLOC	Expense	Active
305010009261712	PBOP COST CAPITALIZED - USC ALLOC	Expense	Active
300003009261800	PROFIT SHARING - COMMON	Expense	Active
304003009261800	PROFIT SHARING - NH	Expense	Active
305003009261800	PROFIT SHARING - ME	Expense	Active
300003009261900	SERP - COMMON	Expense	Active
304003009261900	SERP - NH	Expense	Active
305003009261900	SERP - ME	Expense	Active
300003009262000	SFAS 112 - COMMON	Expense	Active
304003009262000	SFAS 112 - NH	Expense	Active
305003009262000	SFAS 112 - ME	Expense	Active
304003009262400	VISION	Expense	Active
305003009262400	VISION	Expense	Active
304003009262401	VISION - EE CONTR	Expense	Active
305003009262401	VISION - EE CONTR	Expense	Active
300001009280100	REG COMM ASSESSMENT/FEES-COMMON	Expense	Active
304001009280100	REG COMM ASSESSMENT/FEES-NH	Expense	Active
305001009280100	REG COMM ASSESSMENT/FEES-ME	Expense	Active
300001009280200	REG COMM EXP - MISC-COMMON	Expense	Active
304001009280200	REG COMM EXP - MISC-NH	Expense	Active
305001009280200	REG COMM EXP - MISC-ME	Expense	Active
300001009280300	REG COMM EXP - LEGAL-COMMON	Expense	Active
300013009280300	PWR SUPPLY - LEGAL-COMMON	Expense	Active
304001009280300	REG COMM EXP - LEGAL-NH	Expense	Active
304013009280300	POWER SUPPLY - LEGAL-NH	Expense	Active
304901779280300	REG COMM EXP - LEGAL - LIEAP	Expense	Active
305001009280300	REG COMM EXP - LEGAL-ME	Expense	Active
305013009280300	POWER SUPPLY - LEGAL-ME	Expense	Active
304080009300000	MISC GENERAL EXP - NH	Expense	Active
305085009300000	MISC GENERAL EXP - ME	Expense	Active
304901109300088	MISC OVERHEAD ALLOWANCE - DEMAND - PEAK - NH	Expense	Active
304901409300088	MISC OVERHEAD ALLOWANCE - DEMAND - OFF PEAK - NH	Expense	Active
304901109300099	MISC OVERHEAD ALLOWANCE - DEMAND - PEAK - NH	Expense	Active
304901409300099	MISC OVERHEAD ALLOWANCE - DEMAND - OFF PEAK - NH	Expense	Active
304080009300100	GENERAL ADVERTISING-NH	Expense	Active
305085009300100	GENERAL ADVERTISING-ME	Expense	Active
300008009300200	TRUSTEE/REGISTRAR EXPENSE - COMMON	Expense	Active
304008009300200	TRUSTEE/REGISTRAR EXPENSE - NH	Expense	Active
305008009300200	TRUSTEE/REGISTRAR EXPENSE - ME	Expense	Active
304080009300300	DUES TO ORGANIZATIONS - NH	Expense	Active
305085009300300	DUES TO ORGANIZATIONS - ME	Expense	Active
304015009300400	DIRECTORS FEES & EXPENSES - NH	Expense	Active
305015009300400	DIRECTORS FEES & EXPENSES - ME	Expense	Active
304080009301100	SVC CENTER CAPITALIZED - NH	Expense	Active
305085009301100	SVC CENTER CAPITALIZED - ME	Expense	Active
300003009302000	MISC EXPENSE	Expense	Active
300010009302000	MISC EXPENSE - COMMON	Expense	Active
304003009302000	MISC EXPENSE	Expense	Active
304010009302000	MISC EXPENSE	Expense	Active
305003009302000	MISC EXPENSE	Expense	Active
305010009302000	MISC EXPENSE	Expense	Active
304002009302400	MISC GENERAL EXPENSES - NH	Expense	Active
305002009302400	MISC GENERAL EXPENSES - ME	Expense	Active
304802009303102	ADVERTISING	Expense	Active
304829009303102	ADVERTISING	Expense	Active
305802009303102	ADVERTISING	Expense	Active
305829009303102	ADVERTISING	Expense	Active
304024009305100	COMMUNITY SPONSORSHIPS-NH	Expense	Active
305024009305100	COMMUNITY SPONSORSHIPS-ME	Expense	Active
304024009305200	OUTREACH AND EDUCATION-NH	Expense	Active
305024009305200	OUTREACH AND EDUCATION-ME	Expense	Active
304024009305300	CUSTOMER COMMUNICATION-NH	Expense	Active
305024009305300	CUSTOMER COMMUNICATION-ME	Expense	Active

Account Code	Description	Type	Status
304024009305400	MEDIA SERVICES-NH	Expense	Active
305024009305400	MEDIA SERVICES-ME	Expense	Active
305024009305900	ME CAST IRON REPLACEMENT	Expense	Active
300024009306000	EMERGENCY COMMUNICATIONS-COMMON	Expense	Active
304024009306000	EMERGENCY COMMUNICATIONS-NU-NH	Expense	Active
305024009306000	EMERGENCY COMMUNICATIONS-NU-ME	Expense	Active
304008009310000	RENT GARAGE SPACE-NH	Expense	Active
304010009310000	RENT	Expense	Active
304080009310000	MISC RENTS-NH	Expense	Active
305085009310000	RENTS-ME	Expense	Active
300010009310100	CAPITAL LEASE INTEREST RECLASS-COMMON	Expense	Active
304010009310100	CAPITAL LEASE INTEREST RECLASS-NH	Expense	Active
305010009310100	CAPITAL LEASE INTEREST RECLASS-ME	Expense	Active
300010009313100	MISC. EXPENSES - COMMON	Expense	Active
300013009313100	MISC. EXPENSES	Expense	Active
304010009313100	MISC. EXPENSES	Expense	Active
304013009313100	MISC. EXPENSES - NH	Expense	Active
305010009313100	MISC. EXPENSES	Expense	Active
305013009313100	MISC. EXPENSES - ME	Expense	Active
304080009320000	MAINT OF GENERAL PLANT - NH	Expense	Active
305085009320000	MAINT OF GENERAL PLANT - ME	Expense	Active
300008009320100	ERC COSTS - COMMON	Expense	Active
304008009320100	ERC COSTS - NH	Expense	Active
305008009320100	ERC RECOVERIES - ME	Expense	Active
304080009320200	MAINT OF GENERAL PLANT - OFFICE - NH	Expense	Active
305085009320200	MAINT OF GENERAL PLANT - OFFICE - ME	Expense	Active
304080009320300	MAINT OF GENERAL PLANT - GROUNDS - NH	Expense	Active
305085009320300	MAINT OF GENERAL PLANT - GROUNDS - ME	Expense	Active
304080009320400	MAINT OF GENERAL PLANT - EQUIP - NH	Expense	Active
305085009320400	MAINT OF GENERAL PLANT - EQUIP - ME	Expense	Active
304080009320500	MAINT OF GENERAL PLANT - SNOW - NH	Expense	Active
305085009320500	MAINT OF GENERAL PLANT - SNOW - ME	Expense	Active
304080009320600	MAINT OF GENERAL PLANT - FLEET - NH	Expense	Active
305085009320600	MAINT OF GENERAL PLANT - FLEET - ME	Expense	Active
304080009320700	MAINT OF GENERAL PLANT - STOREROOM - NH	Expense	Active
305085009320700	MAINT OF GENERAL PLANT - STOREROOM - ME	Expense	Active
304080009320800	MAINT OF GENERAL PLANT - NON PROD - NH	Expense	Active
305085009320800	MAINT OF GENERAL PLANT - NON PROD - ME	Expense	Active
304080009323800	MAINT GENERAL PLANT-SUPERVISOR	Expense	Active
305085009323800	MAINT GENERAL PLANT-SUPERVISOR	Expense	Active
304080009330000	P/R-MISC.	Expense	Active
305085009330000	P/R-MISC.	Expense	Active
304080009340000	EMPLOYEE RELATIONS - NH	Expense	Active
305085009340000	EMPLOYEE RELATIONS - ME	Expense	Active
304080009350100	MAINTENANCE - GENERAL STRUCTURES - NH	Expense	Active
305085009350100	MAINTENANCE - GENERAL STRUCTURES - ME	Expense	Active
304080009350200	MAINTENANCE - OFFICE EQUIPMENT - NH	Expense	Active
305085009350200	MAINTENANCE - OFFICE EQUIPMENT - ME	Expense	Active
304010009351100	SVC CENTER CAPITALIZED - NH	Expense	Active
304080009351100	SVC CENTER CAPITALIZED - ME	Expense	Active
305010009351100	SVC CENTER CAPITALIZED- ME	Expense	Active
305085009351100	SVC CENTER CAPITALIZED - ME	Expense	Active
300010009999999	SUSPENSE ACCOUNT - COMMON	Expense	Active

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(10) The utility's Securities and Exchange Commission 10K forms and 10Q forms, for the most recent 2 years.

Response:

Northern Utilities, Inc. does not make Form 10-K or Form 10-Q filings. Please see response to Request No. 25.10 for Unitil Corporation's Form 10-K and Form 10-Q filings for the most recent two years.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(11) Detailed list of all membership fees, dues, and donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all membership fees, dues and donations shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all membership fees, dues and donations of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all membership fees, dues and donations of $2,500 and more shall be reported; and
d. If the utility's annual gross revenue s are $100,000,000 or are in excess of $100,000,000, all membership fees, dues and donations of $5,000 and more shall be reported.

Response:

There are no expenses in this category that reach the $2,500 threshold which applies to Northern Utilities, Inc.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(12) A list of any management audit and depreciation studies performed within the last 5 years, specifying whether same are on file with the commission.

Response:

A depreciation study was performed in 2007, based on Gas Plant in Service at December 31, 2006. The study was not submitted to the Commission. Refer to response (13) for a copy of the study. It is the Company's intention to include an updated depreciation study in this proceeding.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(13) Copies of any audits or studies referred to in (12) above which the utility has not submitted to the commission.

Response:

A copy of the depreciation study performed in 2007, based on Gas Plant in Service at December 31, 2006 is attached.

There are no audits performed within the last five years that have not been submitted to the Commission.

NORTHERN UTILITIES, INC.
New Hampshire

Depreciation Study
as of
December 31, 2006

AUS CONSULTANTS
792 Old Highway 66, Suite 200
Tijeras, NM 87059
PHONE: (717) 763-9890
FAX: (775) 243-4056
E-MAIL: erobinson@wfw-ausinc.com

Earl M. Robinson, CDP
Principal & Director

October 26, 2007

Mr. Robert G Kriner
Controller-Distribution Segment
NiSource Corporate Services
200 Civic Center Drive
Columbus, OH 43215

Dear Mr. Kriner: Re-Northern Utilities-NH Depr. Study

In accordance with your authorization, we have prepared a depreciation study related to the utility plant in service of Northern Utilities, Inc. - New Hampshire as of December 31, 2006. Our findings and recommendations, together with supporting schedules and exhibits, are set forth in the accompanying report.

Summary schedules have been prepared to illustrate the impact of instituting the recommended annual depreciation rates as a basis for the Company's annual depreciation expense as compared to the rates presently utilized. The application of the present rates to the depreciable plant in service as of December 31, 2006 results in an annual depreciation expense of $3,184,870. In comparison, the application of the proposed depreciation rates to the depreciable plant in service at December 31, 2006 results in an annual depreciation expense and depreciation reserve amortization of $3,597,712, a depreciation expense increase of $412,842. In addition, the annual amortization of the variance between the Company's book depreciation reserve and theoretical depreciation reserve increased from the present annual amount of $76,024 to $148,125. The composite annual depreciation rate under present rates is 3.19 percent, while the proposed composite depreciation rate is 3.61 percent.

Section 2 of our report contains the summary schedules showing the results of our service life and salvage studies and summaries of presently utilized depreciation rates. The subsequent sections of the report present a detailed outline of the methodology and procedures used in the study together with supporting calculations and analyses used in the development of the results. A detailed table of contents follows this letter.

Respectfully submitted,

Earl M Robinson

EARL M. ROBINSON

TABLE OF CONTENTS

TABLE OF CONTENTS

Section 1

NORTHERN UTILITIES, INC.
New Hampshire

Executive Summary

Table 1-WL-Total on pages 2-1 and 2-4 is a comparative summary which illustrates the effect of instituting the revised depreciation. The schedule includes a comparison of the annual depreciation rates and annual depreciation expense under both present and proposed rates applied using the Straight Line Method for each depreciable property group of the Northern Utilities, Inc. - New Hampshire's (the "Company") plant in service as of December 31, 2006. Both the present and proposed depreciation rates, at the commission staff's urging, are based upon the Broad Group procedure and Whole Life Technique along with an account level amortization of the variance between the account level book depreciation reserve. The present amortization period is based upon an amortization of the reserve variance over five (5) years, while the proposed amortization level period is based upon the average remaining life of each of the property groups.

Table 2-WL-Total on pages 2-5 and 2-6 provides a summary of the detailed life estimates and service life parameters (Iowa Curves) utilized in preparing the Whole Life depreciation rates and related depreciation reserve amortizations for each property group. That is, the schedule provides a summary of the detailed data and a narrative of the study results set forth in Sections 4 through 9. The developed depreciation rates were determined by studying the Company's historical investment data together with the interpretation of future life expectancies which will have a bearing on the overall service life of the Company's property. Likewise, the annual depreciation reserve amortizations are based upon the application of the proposed service life parameters to the Company's

December 31, 2006 investment versus the Company's actual book depreciation reserve.

Table 2-WL-Plant Only on pages 2-7 thru 2-8 (which is the development of the depreciation rates for the Plant Only recovery component) provides a summary of the detailed life estimates and service life parameters (Iowa Curves) utilized in preparing the depreciation rates for each property group. The schedule provides a summary of the detailed data and narrative of the study results set forth in Sections 4 through 7. The developed depreciation rates were determined by studying the Company's historical investment data together with the interpretation of future life expectancies which will have a bearing on the overall service life of the Company's property.

Table 2-WL-Gross Salvage on pages 2-9 thru 2-10 is a similar table to Table 2-WL-Plant Only, except that this table develops the component level depreciation rates for the recovery of the gross salvage portion of the property cost.

Table 2-WL-Cost of Removal on pages 2-11 thru 2-12 summarizes the depreciation recovery rates for the cost of removal segment of the total plant cost.

The utilization of the recommended depreciation rates are based upon the Straight Line/Broad Group/Whole Life Method, Procedure, and Technique results in the setting of depreciation rates and the annual reserve amortization which will generally true up the Company's level of capital recovery over the life of each asset group. The application of this depreciation approach, which is based upon the current best estimates of service life together with the Company's plant in service and accrued depreciation, produces annual depreciation that will better recover the Company's property investments.

It is recommended that the Company continue to apply depreciation rates and depreciation reserve amortizations and maintain its book depreciation reserve on an account-level basis. This maintenance of the book reserve on an account-level basis requires both the development of annual depreciation expense and distribution of other reserve account charges to an individual level. Continuing to maintain the Company's depreciation records in this detail will aid in completing the various rate studies and, most importantly, clearly identify the Company's level of capital recovery relative to each category of plant investment.

The results of this study produced numerous revisions to the applicable account/sub-account level service life parameters. While various of the resulting depreciation modifications were limited in scope resulting in fine tuning of the current recovery, other changes were more significant. The most significant changes in depreciation resulting from this study are for Account 376.20 - Steel (Coated & Wrapped) Mains, Account 376.40 - Plastic Mains, and Account 380.40 - Plastic Services.

The annual depreciation and amortization for Account 367.20 Mains - Steel (Coated and Wrapped) Mains increased from $362,198 to $437,611. No change is being proposed to the underlying service life and salvage parameters. The depreciation is being driven entirely by the change in the amortization of the variance between the Company's current book depreciation reserve and the theoretical depreciation reserve. That is, the level of recent investment activity since the previous depreciation study has driven the book depreciation below the level that should theoretically exist.

The combined annual depreciation and amortization for Account 376.40 - Plastic Mains when applied to the Company's December 31, 2006 plant in service increased from $780,036 to $1,082,071. This change in the annual depreciation rate plus amortization is the result of a change in the anticipated life of this property category which is based upon the current limited use and expectation of the facility being retired in the foreseeable future as well as a change in the level of the annual amortization of the book versus theoretical depreciation reserve variance. In the prior depreciation study, a 50 year average service life was initially estimated for this property group. In the course of settlement negotiations with Staff the average service life was extended to 55 years. The current life analysis clearly demonstrates that not only was the initially proposed life of 50 years warranted, but that the life indication is now a shorter 45 years. No change is proposed to the current underlying net salvage of negative twenty-five (25) percent. The remaining portion of the increase of total depreciation expense and reserve amortization is that the annual amortization increased from a negative $80,604 to a positive $28,913.

The depreciation expense and amortization for Account 380.40 - Plastic Services increased from $1,065,388 to $1,177,699. The depreciation plus amortization increase is the product of the use of a revised average service life reflective of the life being achieved by the current plant in service. A present composite average service life of forty-two (42) years was the product of the prior study settlement. Current analysis demonstrates a life indication of forty (40) years is more appropriate for this property category. An analysis of the Company's net salvage experience identifies that the negative net salvage has been increasing over time and is anticipated to be much higher than the level current incorporated within the present depreciation rates. The proposed net salvage parameter was revised from the present negative sixty (60) percent to negative eighty-five (85) percent. Conversely the annual reserve variance amortization declined from $174,659 to $99,234.

As noted, a variety of other lesser depreciation changes, both increases and decreases, occurred in the remaining plant accounts. In summary, the net change in annual **depreciation expense plus reserve amortization** over the application of present depreciation rates plus amortization produces a proposed depreciation expense increase of $484,943 when applied to the Company's plant in service as of December 31, 2006.

In summary, the Company's historical experience, etc. was studied in detail for each depreciable group in the process of preparing this study. Thus, the resultant proposed depreciation should be applied on a similar basis. Accordingly, the following composite summary is provided for illustrative purposes only as a means to compare the present and proposed composite depreciation rates.

Present Depreciation Rates

Depreciable Plant In Service at December 31, 2006	$99,735,942
Annual Depreciation Expense	3,184,870
Composite Annual Depreciation Rate	3.19%
Annual Depreciation Reserve Amortization	76,024

Proposed Depreciation Rates Plus Depr Reserve Amortization

Depreciable Plant In Service at December 31, 2000	$99,735,942
Annual Depreciation Expense	3,597,712
Composite Annual Depreciation Rate	3.61%
Annual Depreciation Reserve Amortization	148,125

Net Change In Proposed Depreciation Rates Plus Depr. Reserve Amortization

Depreciable Plant In Service at December 31, 2000	$0
Annual Depreciation Expense	412,842
Composite Annual Depreciation Rate	.42%
Annual Depreciation Reserve Amortization	72,101

Section 2

Table 1-WL-Total

Northern Utilities, Inc.
New Hampshire

Summary or Original Cost of Utility Plant in Service as of Dec 31, 2006
and Related Annual Depreciation Expense Under Present Rates
And Annual Depreciation Expense Plus Depreciation Reserve
Amortization Under Proposed Depreciation

Account No.	Description	Original Cost 12-31-2006	Present Rates: Rate %	Present Rates: Annual Accrual	Present Rates: Annual Depr Resr Amort.	Present Rates: Total Accrual Plus Amort.	Proposed Rates: Plant Only Rate %	Plant Only Ann. Accrual	Gross Salv Rate %	Gross Salv Ann. Accrual	Cost of Removal Rate %	Cost of Removal Ann. Accrual
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	DEPRECIABLE PLANT											
	Structures											
305.00	(13081) Production Plant Structures	80,968.05	11.05% (1)	8,946.97	6,228.07	15,175.04	8.13%	6,582.77	0.00%	0.00	0.41%	329.14
375.20	366.00 Str, City Gate Mea & Reg	48,195.00	3.00% (1)	1,445.85	-1,524.17	-78.32	2.72%	1,312.50	0.00%	0.00	0.14%	65.63
375.70	390.00(13086) Distribution System Struct	2,286,937.84	1.95% (1)	44,595.29	-38,678.37	5,916.92	2.63%	60,119.29	0.00%	0.00	0.00%	0.00
	TOTAL Structures	2,416,100.89	2.28%	54,988.11	-33,974.47	21,013.64	2.82%	68,014.56	0.00%	0.00	0.02%	394.77
	Production Equipment											
311.00	(13210) Other Gas Generating Equipment	373,861.73	5.11% (1)	19,104.33	11,758.80	30,863.13	4.19%	15,655.85	0.00%	0.00	0.42%	1,565.59
320.00	(13300) Other Production Equipment	7,640.16	5.00%	382.01	27.28	409.29	5.00%	382.01	0.00%	0.00	0.00%	0.00
321.00	(13300) LNG Equipment	56,860.76	5.00%	2,843.04	735.69	3,578.73	5.00%	2,843.04	0.00%	0.00	0.00%	0.00
	TOTAL Production Equipment	438,362.65	5.09%	22,329.38	12,521.77	34,851.15	4.31%	18,880.90	0.00%	0.00	0.36%	1,565.59
	Distribution Equipment											
	MAINS											
376.20	(13564) Steel Mains (Coated & Wrapped)	15,171,551.64	2.78%	421,769.14	-59,570.70	362,198.44	2.22%	337,145.59	0.00%	0.00	0.56%	84,286.40
376.30	(13566) Steel Mains (Bare)	410,240.41	4.03%	16,532.69	-8,708.87	7,823.82	3.23%	13,233.56	0.00%	0.00	0.81%	3,308.39
376.40	(13567) Plastic Mains	37,913,691.18	2.27%	860,640.79	-80,604.43	780,036.36	2.22%	842,526.47	0.00%	0.00	0.56%	210,631.62
376.50	(13562) Joint Clamps	559,872.74	8.33%	46,637.40	-278.55	46,358.85	6.67%	37,324.85	0.00%	0.00	1.67%	9,331.21
376.60	(13565) Cathodic Protection	308,767.26	6.94%	21,428.45	-1,050.06	20,378.39	5.56%	17,153.74	0.00%	0.00	1.39%	4,288.43
376.80	(13561) Cast Iron Mains	87,713.39	2.02%	1,771.81	-2,107.05	-335.24	1.61%	1,414.73	0.00%	0.00	0.40%	353.68
	Total Mains	54,451,836.62	2.51%	1,368,780.28	-152,319.66	1,216,460.62	2.29%	1,248,798.94	0.00%	0.00	0.57%	312,199.73
378.20	369.00 (13580) Pumping and Regulating Eq.	1,953,245.39	4.38%	85,552.15	13,750.71	99,302.86	3.33%	65,108.18	0.00%	0.00	0.17%	3,255.41
	SERVICES											
380.10	(13591) Bare Steel	204,647.36	3.82%	7,817.53	9,761.05	17,578.58	2.13%	4,354.20	0.00%	0.00	1.81%	3,701.07
380.20	(13592) Coated Steel Not Wrapped	253,890.14	3.82%	9,698.60	10,415.20	20,113.80	2.63%	6,681.32	0.00%	0.00	2.24%	5,679.12
380.30	(13593) Steel Coated & Wrapped	142,123.50	3.82%	5,429.12	3,704.59	9,133.71	2.63%	3,740.09	0.00%	0.00	2.24%	3,179.08
380.40	(13594) Plastic	23,317,516.88	3.82%	890,729.14	174,659.09	1,065,388.23	2.50%	582,937.92	0.00%	0.00	2.13%	495,497.23
	Total Services	23,918,177.88	3.82%	913,674.39	198,539.93	1,112,214.32	2.50%	597,713.53	0.00%	0.00	2.12%	508,056.50
381.00	(13600) Customers' Meters	2,432,022.55	3.33%	80,986.35	5,726.33	86,712.68	3.33%	81,067.42	0.00%	0.00	0.00%	0.00
382.00	(13600) Customers' Meters Installations	9,196,255.72	3.33%	306,235.32	10,869.17	317,104.49	3.13%	287,382.99	0.00%	0.00	0.31%	28,738.30
383.00	(13600) Gas Regulators	185,195.22	3.33%	6,167.00	78.83	6,245.83	3.33%	6,173.17	0.00%	0.00	0.00%	0.00
386.10/.20	(13610) Misc. Prop on Cust. Prem-WH & CB	1,159,597.03	7.50%	86,969.78	18,888.57	105,858.35	10.00%	115,959.70	-0.50%	-5,797.99	0.00%	0.00
	TOTAL Distribution Equipment	93,296,330.41	3.05%	2,848,365.27	95,533.88	2,943,899.15	2.57%	2,402,203.93	-0.01%	-5,797.99	0.91%	852,249.94

Table 1-WL-Total

Northern Utilities, Inc.
New Hampshire

Summary or Original Cost of Utility Plant in Service as of Dec 31, 2006
and Related Annual Depreciation Expense Under Present Rates
And Annual Depreciation Expense Plus Depreciation Reserve
Amortization Under Proposed Depreciation

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Present Rates Annual Depr Resr Amort. (f)	Present Rates Total Accrual Plus Amort. (g)	Proposed Rates Plant Only Rate % (h)	Proposed Rates Plant Only Ann. Accrual (i)	Proposed Rates Gross Salv Rate % (j)	Proposed Rates Gross Salv Ann. Accrual (k)	Proposed Rates Cost of Removal Rate % (l)	Proposed Rates Cost of Removal Ann. Accrual (m)
	General Equipment											
	OFFICE EQUIPMENT											
391.10	39110 OF&E, Unspecified	556,427.93	7.92%	44,069.09	4,371.61	48,440.70	9.09%	50,584.36	-0.18%	-1,011.69	0.00%	0.00
391.11	39111 OF&E, Data Handling Equip	7,565.50	0.00%	0.00	0.00	0.00	10.00%	756.55	0.00%	0.00	0.00%	0.00
391.12	(13721) Information System	123,869.53	12.50%	15,483.69	8,651.25	24,134.94	12.50%	15,483.69	0.00%	0.00	0.00%	0.00
	Total Office Furniture & Equipment	687,862.96	8.66%	59,552.78	13,022.86	72,575.64	9.71%	66,824.60	-0.15%	-1,011.69	0.00%	0.00
392.00	(13730) Transportation Equipment	38,676.09	0.00%	0.00	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00
393.00	(13740) Stores Equipment	31,519.95	8.33%	2,625.61	-216.93	2,408.68	7.69%	2,424.61	0.00%	0.00	0.00%	0.00
394.10	387.00 Tools, Garage & Service Eq	438,189.86	5.88%	25,765.56	-396.21	25,369.35	5.26%	23,062.62	-0.11%	-461.25	0.00%	0.00
394.30	39400 Tools, Tools & Other	87,971.27	5.00%	4,398.56	0.00	4,398.56	5.56%	4,887.29	-0.11%	-97.75	0.00%	0.00
396.00	39600 Power Operated Equipment	75,266.49	5.00%	3,763.32	-6,918.98	-3,155.66	6.67%	5,017.77	-0.67%	-501.78	0.00%	0.00
397.00	39700 Communication Equipment	321,225.57	8.33%	26,758.09	-3,547.45	23,210.64	10.00%	32,122.56	0.00%	0.00	0.00%	0.00
397.25	39725 Comm Eq, Metscan/Telemetering	29,126.60	8.33%	2,426.25	0.00	2,426.25	10.00%	2,912.66	0.00%	0.00	0.00%	0.00
397.35	39735 Comm Eq, ITRON Equipment	1,875,309.16	7.14%	133,897.07	0.00	133,897.07	6.67%	125,020.61	0.00%	0.00	0.00%	0.00
	TOTAL General Equipment	3,585,147.95	6.40%	259,187.24	1,943.29	261,130.53	7.32%	262,272.72	-0.06%	-2,072.47	0.00%	0.00
	TOTAL Depreciable Plant	99,735,941.90	3.19%	3,184,870.00	76,024.47	3,260,894.47	2.76%	2,751,372.11	-0.01%	-7,870.46	0.86%	854,210.30
	NON-DEPRECIABLE PLANT											
	NON-DEPRECIABLE											
365.00	(13072) Rights of Way	0.00										
374.40	37440 Land Rgts, Other Distr Sys	89,408.82										
374.50	37450 Rights of Way	17,910.67										
389.00	(13073) General and Miscellaneous Land	232,946.85										
	Total Land	340,266.34										
	INTANGIBLE PLANT											
303.00	(13030) Miscellaneous Intangible Plant	2,328,373.75										
304.00	(13040) Land Rights	6,816.33										
	Total Intangible Plant	2,335,190.08										
386.30	38630 Diamond Boiler	1,148,341.31										
	TOTAL Non-Depreciable Plant	3,823,797.73										
	TOTAL Plant in Service	103,559,739.63										

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.
(2) Adjusted for Estimated Future Net Salvage Account 392 Is Currently Fully Depreciated.
No Further Depreciation Should Be Accrued At The Present Time.

Table 1-WL-Total

Northern Utilities, Inc.
New Hampshire

Summary or Original Cost of Utility Plant in Service as of Dec 31, 2006 and Related Annual Depreciation Expense Under Present Rates And Annual Depreciation Expense Plus Depreciation Reserve Amortization Under Proposed Depreciation

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	Total Proposed Rate % (n)	Total Proposed Ann. Accrual (o)	Proposed Annual Depr. Reserve Amortization Plant Only (p)	Gross Salv (q)	COR (r)	Total (s)	Total Proposed Accrual Plus Amortization (t)	Net Change in Annual Provision (u)
	DEPRECIABLE PLANT									
	Structures									
305.00	(13081) Production Plant Structures	80,968.05	8.54%	6,911.91	-2,625.60	0.00	-131.73	-2,757.34	4,154.57	-11,020.47
375.20	366.00 Str, City Gate Mea & Reg	48,195.00	2.86%	1,378.13	559.22	0.00	31.78	591.01	1,969.14	2,047.46
375.70	390.00(13086) Distribution System Struct	2,286,937.84	2.63%	60,119.29	-1,322.81	6,267.77	0.00	4,944.95	65,064.24	59,147.32
	TOTAL Structures	2,416,100.89	2.83%	68,409.33	-3,389.19	6,267.77	-99.95	2,778.62	71,187.95	50,174.31
	Production Equipment									
311.00	(13210) Other Gas Generating Equipment	373,861.73	4.61%	17,221.44	-51,746.02	0.00	27.00	-51,719.02	-34,497.58	-65,360.71
320.00	(13300) Other Production Equipment	7,640.16	5.00%	382.01	562.57	0.00	0.00	562.57	944.58	535.29
321.00	(13300) LNG Equipment	56,860.76	5.00%	2,843.04	-757.26	0.00	0.00	-757.26	2,085.78	-1,492.95
	TOTAL Production Equipment	438,362.65	4.66%	20,446.49	-51,940.71	0.00	27.00	-51,913.71	-31,467.22	-66,318.37
	Distribution Equipment									
	MAINS									
376.20	(13564) Steel Mains (Coated & Wrapped)	15,171,551.64	2.78%	421,431.99	13,477.22	0.00	2,701.41	16,178.63	437,610.62	75,412.18
376.30	(13566) Steel Mains (Bare)	410,240.41	4.03%	16,541.95	4,821.97	0.00	966.60	5,788.57	22,330.52	14,506.70
376.40	(13567) Plastic Mains	37,913,691.18	2.78%	1,053,158.09	24,084.90	0.00	4,827.65	28,912.56	1,082,070.65	302,034.29
376.50	(13562) Joint Clamps	559,872.74	8.33%	46,656.06	39,257.56	0.00	9,732.10	48,989.67	95,645.73	49,286.88
376.60	(13565) Cathodic Protection	308,767.26	6.94%	21,442.17	1,100.50	0.00	220.56	1,321.06	22,763.23	2,384.84
376.80	(13561) Cast Iron Mains	87,713.39	2.02%	1,768.42	1,296.95	0.00	259.92	1,556.87	3,325.29	3,660.53
	Total Mains	54,451,836.62	2.87%	1,560,998.68	84,039.10	0.00	18,708.25	102,747.35	1,663,746.03	447,285.41
378.20	369.00 (13580) Pumping and Regulating Eq.	1,953,245.39	3.50%	68,363.59	-9,370.10	0.00	-468.54	-9,838.64	58,524.95	-40,777.91
	SERVICES									
380.10	(13591) Bare Steel	204,647.36	3.94%	8,055.27	1,543.01	0.00	5,073.71	6,616.72	14,671.99	-2,906.59
380.20	(13592) Coated Steel Not Wrapped	253,890.14	4.87%	12,360.44	1,525.54	0.00	5,016.32	6,541.87	18,902.31	-1,211.49
380.30	(13593) Steel Coated & Wrapped	142,123.50	4.87%	6,919.17	439.28	0.00	1,444.51	1,883.80	8,802.97	-330.74
380.40	(13594) Plastic	23,317,516.88	4.63%	1,078,435.16	23,141.12	0.00	76,093.06	99,234.18	1,177,669.34	112,281.11
	Total Services	23,918,177.88	4.62%	1,105,770.04	26,648.95	0.00	87,627.61	114,276.56	1,220,046.60	107,832.28
381.00	(13600) Customers' Meters	2,432,022.55	3.33%	81,067.42	-2,092.33	0.00	0.00	-2,092.33	78,975.09	-7,737.59
382.00	(13600) Customers' Meters Installations	9,196,255.72	3.44%	316,121.29	4,055.03	0.00	397.33	4,452.36	320,573.65	3,469.16
383.00	(13600) Gas Regulators	185,195.22	3.33%	6,173.17	91.65	0.00	0.00	91.65	6,264.82	18.99
386.10/.20	(13610) Misc. Prop on Cust. Prem-WH & CB	1,159,597.03	9.50%	110,161.72	3,806.71	18,876.88	0.00	22,683.59	132,845.31	26,986.96
	TOTAL Distribution Equipment	93,296,330.41	3.48%	3,248,655.91	107,179.02	18,876.88	106,264.65	232,320.55	3,480,976.46	537,077.31

Table 1-WL-Total

Northern Utilities, Inc.
New Hampshire

Summary or Original Cost of Utility Plant in Service as of Dec 31, 2006
and Related Annual Depreciation Expense Under Present Rates
And Annual Depreciation Expense Plus Depreciation Reserve
Amortization Under Proposed Depreciation

Account		Original	Total Proposed		Proposed Annual Depr. Reserve Amortization				Total Proposed	Net
		Cost							Accrual Plus	Change in
No.	Description	12-31-2006	Rate %	Ann. Accrual	Plant Only	Gross Salv	COR	Total	Amortization	Annual Provision
(a)	(b)	(c)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
	General Equipment									
	OFFICE EQUIPMENT									
391.10	39110 OF&E, Unspecified	556,427.93	8.91%	49,572.67	-35,870.99	1,025.81	0.00	-34,845.19	14,727.48	-33,713.22
391.11	39111 OF&E, Data Handling Equip	7,565.50	10.00%	756.55	250.60	0.00	0.00	250.60	1,007.15	1,007.15
391.12	(13721) Information System	123,869.53	12.50%	15,483.69	-4,864.72	0.00	0.00	-4,864.72	10,618.97	-13,515.97
	Total Office Furniture & Equipment	687,862.96	9.57%	65,812.91	-40,485.11	1,025.81	0.00	-39,459.31	26,353.60	-46,222.04
392.00	(13730) Transportation Equipment	38,676.09	0.00%	0.00	0.00	0.00	0.00	0.00	0.00	0.00 (2)
393.00	(13740) Stores Equipment	31,519.95	7.69%	2,424.61	-2,420.60	0.00	0.00	-2,420.60	4.01	-2,404.67
394.10	387.00 Tools, Garage & Service Eq	438,189.86	5.16%	22,601.37	-4,127.77	1,230.95	0.00	-2,896.82	19,704.55	-5,664.80
394.30	39400 Tools, Tools & Other	87,971.27	5.44%	4,789.55	-1,077.73	-43.79	0.00	-1,121.53	3,668.03	-730.54
396.00	39600 Power Operated Equipment	75,268.49	6.00%	4,515.99	13,544.00	-2,032.32	0.00	11,511.68	16,027.67	19,183.33
397.00	39700 Communication Equipment	321,225.57	10.00%	32,122.56	-19,091.08	488.30	0.00	-18,602.78	13,519.78	-9,690.86
397.25	39725 Comm Eq, Metscan/Telemetering	29,126.60	10.00%	2,912.66	219.42	0.00	0.00	219.42	3,132.08	705.83
397.35	39735 Comm Eq, ITRON Equipment	1,875,309.16	6.67%	125,020.61	17,709.72	0.00	0.00	17,709.72	142,730.33	8,833.26
	TOTAL General Equipment	3,585,147.95	7.26%	260,200.26	-35,729.16	668.94	0.00	-35,060.22	225,140.04	-35,990.49
	TOTAL Depreciable Plant	99,735,941.90	3.61%	3,597,711.99	16,119.95	25,813.59	106,191.70	148,125.24	3,745,837.23	484,942.76
	NON-DEPRECIABLE PLANT									
	NON-DEPRECIABLE									
365.00	(13072) Rights of Way	0.00								
374.40	37440 Land Rgts, Other Distr Sys	89,408.82								
374.50	37450 Rights of Way	17,910.67								
389.00	(13073) General and Miscellaneous Land	232,946.85								
	Total Land	340,266.34								
	INTANGIBLE PLANT									
303.00	(13030) Miscellaneous Intangible Plant	2,328,373.75								
304.00	(13040) Land Rights	6,816.33								
	Total Intangible Plant	2,335,190.08								
386.30	38630 Diamond Boiler	1,148,341.31								
	TOTAL Non-Depreciable Plant	3,823,797.73								
	TOTAL Plant in Service	103,559,739.63								

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.
(2) Adjusted for Estimated Future Net Salvage Account 392 Is Currently Fully Depreciated.
No Further Depreciation Should Be Accrued At The Present Time.

Table 2-WL-Total

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	(d)	A.S.L./ Survivor Curve (e)	Net Salvage % (f)	Annual Depreciation Rate - % (g)	Annual Depreciation Expense (h)	Book Depreciation Reserve (i)	Theoretical Depreciation Reserve (j)	Theor. Reserve Over (Under) Book Reserve (k)	Average Remaining Life (l)	Annual Resr. Variance Amortization (m)	Total Annual Depr Expense Plus Resrv. Amort. (n)
	DEPRECIABLE PLANT												
	Structures												
305.00	(13081) Production Plant Structures	80,968.05	(1)	No Int	-5%	8.54%	6,911.91	80,302.07	77,269.00	-3,033.07	1.1	-2,757.34	4,154.57
375.20	366.00 Str, City Gate Mea & Reg	48,195.00	(1)	80-L0	-5%	2.86%	1,378.13	-10,540.75	7,810.00	18,350.75	31.1	591.01	1,969.14
375.70	390.00(13086) Distribution System Struct	2,286,937.84	(1)	80-L0	0%	2.63%	60,119.29	742,730.58	859,926.00	117,195.42	23.7	4,944.95	65,064.24
	TOTAL Structures	2,416,100.89				2.83%	68,409.33	812,491.90	945,005.00	132,513.10		2,776.62	71,187.95
	Production Equipment												
311.00	(13210) Other Gas Generating Equipment	373,861.73	(1)	No Int	-10%	4.61%	17,221.44	428,495.51	402,636.00	-25,859.51	0.5	-51,719.02	-34,497.58
320.00	(13300) Other Production Equipment	7,840.16		20-R4	0%	5.00%	382.01	622.13	4,802.00	4,179.87	7.4	562.57	944.58
321.00	(13300) LNG Equipment	56,860.76		20-R5	0%	5.00%	2,843.04	49,369.62	44,243.00	-5,126.62	6.8	-757.26	2,085.78
	TOTAL Production Equipment	438,362.65				4.66%	20,446.49	478,487.26	451,681.00	-26,806.26		-51,913.71	-31,487.22
	Distribution Equipment												
	MAINS												
376.20	(13564) Steel Mains (Coated & Wrapped)	15,171,551.64		45-R3	-25%	2.78%	421,431.99	5,032,078.62	5,546,559.00	514,480.38	31.8	16,178.63	437,610.62
376.30	(13566) Steel Mains (Bare)	410,240.41		31-L3	-25%	4.03%	16,541.95	368,579.39	406,263.00	37,683.61	6.5	5,788.57	22,330.52
376.40	(13567) Plastic Mains	37,913,691.18		45-S2	-25%	2.78%	1,053,158.09	9,812,836.33	10,816,102.00	1,003,265.67	34.7	28,912.56	1,082,070.65
376.50	(13562) Joint Clamps	559,872.74		15-S6	-25%	8.33%	46,656.06	118,923.04	417,760.00	298,836.96	6.1	48,989.67	95,645.73
376.60	(13565) Cathodic Protection	308,767.26		18-R5	-25%	6.94%	21,442.17	139,548.54	153,816.00	14,267.46	10.8	1,321.06	22,763.23
376.80	(13561) Cast Iron Mains	87,713.39		62-S5	-25%	2.02%	1,768.42	89,994.91	99,196.00	9,201.09	5.9	1,556.87	3,325.29
	Total Mains	54,451,836.62				2.87%	1,560,998.68	15,561,960.83	17,439,696.00	1,877,735.17		102,747.35	1,663,746.03
378.20	369.00 (13580) Pumping and Regulating Eq.	1,953,245.39		30-R3	-5%	3.50%	68,363.59	843,336.95	640,661.00	-202,675.95	20.6	-9,838.64	58,524.95
	SERVICES												
380.10	(13591) Bare Steel	204,647.36		47-R3	-85%	3.94%	8,055.27	223,406.46	296,852.00	73,445.54	11.1	6,616.72	14,671.99
380.20	(13592) Coated Steel Not Wrapped	253,890.14		38-L3	-85%	4.87%	12,360.44	244,758.06	325,223.00	80,464.94	12.3	6,541.87	18,902.31
380.30	(13593) Steel Coated & Wrapped	142,123.50		38-R1.5	-85%	4.87%	6,919.17	104,861.48	139,335.00	34,473.52	18.3	1,883.80	8,802.97
380.40	(13594) Plastic	23,317,516.88		40-R3	-85%	4.63%	1,078,435.16	8,844,213.50	11,751,775.00	2,907,561.50	29.3	99,234.18	1,177,669.34
	Total Services	23,918,177.88				4.62%	1,105,770.04	9,417,239.50	12,513,185.00	3,095,945.50		114,276.56	1,220,046.60
381.00	(13600) Customers' Meters	2,432,022.55		30-R5	0%	3.33%	81,067.42	1,362,620.45	1,334,374.00	-28,246.45	13.5	-2,092.33	78,975.09
382.00	(13600) Customers' Meters Installations	9,196,255.72		32-R4	-10%	3.44%	316,121.29	2,661,973.18	2,765,268.00	103,294.82	23.2	4,452.36	320,573.65
383.00	(13600) Gas Regulators	185,195.22		30-R3	0%	3.33%	6,173.17	27,339.30	29,649.00	2,309.70	25.2	91.65	6,264.82
386.10/.20	(13610) Misc. Prop on Cust. Prem-WH & CB	1,159,597.03		10-R1.5	5%	9.50%	110,161.72	415,716.35	533,671.00	117,954.65	5.2	22,683.59	132,845.31
	TOTAL Distribution Equipment	93,296,330.41				3.48%	3,248,655.91	30,290,186.56	35,256,504.00	4,966,317.44		232,320.55	3,480,976.46

Table 2-WL-Total

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	(d)	A.S.L./ Survivor Curve (e)	Net Salvage % (f)	Annual Depreciation Rate - % (g)	Annual Depreciation Expense (h)	Book Depreciation Reserve (i)	Theoretical Depreciation Reserve (j)	Theor. Reserve Over (Under) Book Reserve (k)	Average Remaining Life (l)	Annual Resr. Variance Amortization (m)	Total Annual Depr Expense Plus Resrv. Amort. (n)
	General Equipment												
	OFFICE EQUIPMENT												
391.10	39110 OF&E, Unspecified	556,427.93		11-S3	2%	8.91%	49,572.67	504,339.17	407,818.00	-96,521.17	2.8	-34,845.19	14,727.48
391.11	39111 OF&E, Data Handling Equip	7,565.50		10-R4	0%	10.00%	756.55	0.00	1,882.00	1,882.00	7.5	250.60	1,007.15
391.12	(13721) Information System	123,869.53		8-L4	0%	12.50%	15,483.69	65,049.54	38,099.00	-26,950.54	5.5	-4,864.72	10,618.97
	Total Office Furniture & Equipment	687,862.96				9.57%	65,812.91	569,388.71	447,799.00	-121,589.71		-39,459.31	26,353.60
392.00	(13730) Transportation Equipment	38,676.09		9-L4	10%	0.00%	0.00	58,634.22	28,253.00	-30,381.22	1.7	0.00	0.00 (2)
393.00	(13740) Stores Equipment	31,519.95		13-L5	0%	7.69%	2,424.61	31,501.87	27,169.00	-4,332.87	1.8	-2,420.60	4.01
394.10	387.00 Tools, Garage & Service Eq	438,189.86		19-R5	2%	5.16%	22,601.37	272,329.63	249,242.00	-23,087.63	8.0	-2,896.82	19,704.55
394.30	39400 Tools, Tools & Other	87,971.27		18-R5	2%	5.44%	4,789.55	40,521.91	26,615.00	-13,906.91	12.4	-1,121.53	3,668.03
396.00	39600 Power Operated Equipment	75,266.49		15-R4	10%	6.00%	4,515.99	20,142.32	54,332.00	34,189.68	3.0	11,511.68	16,027.67
397.00	39700 Communication Equipment	321,225.57		10-L3	0%	10.00%	32,122.56	320,929.95	167,457.00	-153,472.95	8.3	-18,602.78	13,519.78
397.25	39725 Comm Eq, Metscan/Telemetering	29,126.60		10-R3	0%	10.00%	2,912.66	2,921.49	4,758.00	1,836.51	8.4	219.42	3,132.08
397.35	39735 Comm Eq, ITRON Equipment	1,875,309.16		15-R3	0%	6.67%	125,020.61	196,319.33	403,523.00	207,203.67	11.7	17,709.72	142,730.33
	TOTAL General Equipment	3,585,147.95				7.26%	260,200.26	1,512,689.43	1,409,148.00	-103,541.43		-35,060.22	225,140.04
	TOTAL Depreciable Plant	99,735,941.90				3.61%	3,597,711.99	33,093,855.15	38,062,338.00	4,968,482.85		148,125.24	3,745,837.23
	NON-DEPRECIABLE PLANT												
	NON-DEPRECIABLE												
365.00	(13072) Rights of Way	0.00											
374.40	37440 Land Rgts, Other Distr Sys	89,408.82											
374.50	37450 Rights of Way	17,910.67											
389.00	(13073) General and Miscellaneous Land	232,946.85											
	Total Land	340,266.34											
	INTANGIBLE PLANT												
303.00	(13030) Miscellaneous Intangible Plant	2,328,373.75											
304.00	(13040) Land Rights	6,816.33											
	Total Intangible Plant	2,335,190.08											
386.30	38630 Diamond Boiler	1,148,341.31											
	TOTAL Non-Depreciable Plant	3,823,797.73											
	TOTAL Plant in Service	103,559,739.63											

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.
(2) Adjusted for Estimated Future Net Salvage Account 392 Is Currently Fully Depreciated.
No Further Depreciation Should Be Accrued At The Present Time.

Table 2-WL-Plant Only

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	(d)	A.S.L./ Survivor Curve (e)	Plant Only Salv % (f)	Annual Depr. Rate - % (g)	Annual Depreciation Expense (h)	Plant Only Book Depreciation Reserve (i)	Plant Only Theoretical Depreciation Reserve (j)	Theor. Reserve Over (Under) Book Reserve (k)	Average Remaining Life (l)	Annual Resr. Variance Amortization (m)	Total Annual Depr Expense Plus Resrv. Amort. (n)
	DEPRECIABLE PLANT												
	Structures												
305.00	(13081) Production Plant Structures	80,968.05	(1)	No Int	0%	8.13%	6,582.77	76,478.16	73,590.00	-2,888.16	1.1	-2,625.60	3,957.17
375.20	366.00 Str, City Gate Mea & Reg	48,195.00	(1)	80-L0	0%	2.72%	1,312.50	-9,925.87	7,438.00	17,363.87	31.1	559.22	1,871.72
375.70	390.00(13086) Distribution System Struct	2,286,937.84	(1)	80-L0	0%	2.63%	60,119.29	891,276.70	859,926.00	-31,350.70	23.7	-1,322.81	58,796.48
	TOTAL Structures	2,416,100.89				2.82%	68,014.56	957,828.99	940,954.00	-16,874.99		-3,389.19	64,625.37
	Production Equipment												
311.00	(13210) Other Gas Generating Equipment	373,861.73	(1)	No Int	0%	4.19%	15,655.85	391,905.01	366,032.00	-25,873.01	0.5	-51,746.02	-36,090.17
320.00	(13300) Other Production Equipment	7,640.16		20-R4	0%	5.00%	382.01	622.13	4,802.00	4,179.87	7.4	562.57	944.58
321.00	(13300) LNG Equipment	56,860.76		20-R5	0%	5.00%	2,843.04	49,369.62	44,243.00	-5,126.62	6.8	-757.26	2,085.78
	TOTAL Production Equipment	438,362.65				4.31%	18,880.90	441,896.76	415,077.00	-26,819.76		-51,940.71	-33,059.81
	Distribution Equipment												
	MAINS												
376.20	(13564) Steel Mains (Coated & Wrapped)	15,171,551.64		45-R3	0%	2.22%	337,145.59	4,008,671.47	4,437,247.00	428,575.53	31.8	13,477.22	350,622.81
376.30	(13566) Steel Mains (Bare)	410,240.41		31-L3	0%	3.23%	13,233.56	293,618.96	325,010.00	31,391.04	6.5	4,821.97	18,055.53
376.40	(13567) Plastic Mains	37,913,691.18		45-S2	0%	2.22%	842,526.47	7,817,134.83	8,652,881.00	835,746.17	34.7	24,084.90	866,611.37
376.50	(13562) Joint Clamps	559,872.74		15-S6	0%	6.67%	37,324.85	94,736.87	334,208.00	239,471.13	6.1	39,257.56	76,582.41
376.60	(13565) Cathodic Protection	308,767.26		18-R5	0%	5.56%	17,153.74	111,167.63	123,053.00	11,885.37	10.8	1,100.50	18,254.24
376.80	(13561) Cast Iron Mains	87,713.39		62-S5	0%	1.61%	1,414.73	71,692.05	79,357.00	7,664.95	5.9	1,296.95	2,711.68
	Total Mains	54,451,836.62				2.29%	1,248,798.94	12,397,021.81	13,951,756.00	1,554,734.19		84,039.10	1,332,838.04
378.20	369.00 (13580) Pumping and Regulating Eq.	1,953,245.39		30-R3	0%	3.33%	65,108.18	803,178.07	610,154.00	-193,024.07	20.6	-9,370.10	55,738.08
	SERVICES												
380.10	(13591) Bare Steel	204,647.36		47-R3	0%	2.13%	4,354.20	139,110.62	156,238.00	17,127.38	11.1	1,543.01	5,897.21
380.20	(13592) Coated Steel Not Wrapped	253,890.14		38-L3	0%	2.63%	6,681.32	152,405.82	171,170.00	18,764.18	12.3	1,525.54	8,206.86
380.30	(13593) Steel Coated & Wrapped	142,123.50		38-R1.5	0%	2.63%	3,740.09	65,295.09	73,334.00	8,038.91	18.3	439.28	4,179.37
380.40	(13594) Plastic	23,317,516.88		40-R3	0%	2.50%	582,937.92	5,507,110.26	6,185,145.00	678,034.74	29.3	23,141.12	606,079.04
	Total Services	23,918,177.88				2.50%	597,713.53	5,863,921.79	6,585,887.00	721,965.21		26,648.95	624,362.48
381.00	(13600) Customers' Meters	2,432,022.55		30-R5	0%	3.33%	81,067.42	1,362,620.45	1,334,374.00	-28,246.45	13.5	-2,092.33	78,975.09
382.00	(13600) Customers' Meters Installations	9,196,255.72		32-R4	0%	3.13%	287,382.99	2,419,803.21	2,513,880.00	94,076.79	23.2	4,055.03	291,438.02
383.00	(13600) Gas Regulators	185,195.22		30-R3	0%	3.33%	6,173.17	27,339.30	29,649.00	2,309.70	25.2	91.65	6,264.82
386.10/.20	(13610) Misc. Prop on Cust. Prem-WH & CB	1,159,597.03		10-R1.5	0%	10.00%	115,959.70	541,964.13	561,759.00	19,794.87	5.2	3,806.71	119,766.41
	TOTAL Distribution Equipment	93,296,330.41				2.57%	2,402,203.93	23,415,848.76	25,587,459.00	2,171,610.24		107,179.02	2,509,382.95

Table 2-WL-Plant Only

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant In Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	(d)	A.S.L./ Survivor Curve (e)	Plant Only Salv % (f)	Annual Depr. Rate - % (g)	Annual Depreciation Expense (h)	Plant Only Book Depreciation Reserve (i)	Plant Only Theoretical Depreciation Reserve (j)	Theor. Reserve Over (Under) Book Reserve (k)	Average Remaining Life (l)	Annual Resr. Variance Amortization (m)	Total Annual Depr Expense Plus Resrv. Amort. (n)
	General Equipment												
	OFFICE EQUIPMENT												
391.10	39110 OF&E, Unspecified	556,427.93		11-S3	0%	9.09%	50,584.36	515,503.65	416,141.00	-99,362.65	2.8	-35,870.99	14,713.37
391.11	39111 OF&E, Data Handling Equip	7,565.50		10-R4	0%	10.00%	756.55	0.00	1,882.00	1,882.00	7.5	250.60	1,007.15
391.12	(13721) Information System	123,869.53		8-L4	0%	12.50%	15,483.69	65,049.54	38,099.00	-26,950.54	5.5	-4,864.72	10,618.97
	Total Office Furniture & Equipment	687,862.96				9.71%	66,824.60	580,553.19	456,122.00	-124,431.19		-40,485.11	26,339.49
392.00	(13730) Transportation Equipment	38,676.09		9-L4	0%	0.00%	0.00	66,282.16	31,392.00	-34,890.16	1.7	0.00	0.00 (2)
393.00	(13740) Stores Equipment	31,519.95		13-L5	0%	7.69%	2,424.61	31,501.87	27,169.00	-4,332.87	1.8	-2,420.60	4.01
394.10	387.00 Tools, Garage & Service Eq	438,189.86		19-R5	0%	5.26%	23,062.62	287,227.32	254,329.00	-32,898.32	8.0	-4,127.77	18,934.85
394.30	39400 Tools, Tools & Other	87,971.27		18-R5	0%	5.56%	4,887.29	40,521.91	27,158.00	-13,363.91	12.4	-1,077.73	3,809.56
396.00	39600 Power Operated Equipment	75,266.49		15-R4	0%	6.67%	5,017.77	20,142.32	60,368.00	40,225.68	3.0	13,544.00	18,561.77
397.00	39700 Communication Equipment	321,225.57		10-L3	0%	10.00%	32,122.56	324,958.41	167,457.00	-157,501.41	8.3	-19,091.08	13,031.48
397.25	39725 Comm Eq, Metscan/Telemetering	29,126.60		10-R3	0%	10.00%	2,912.66	2,921.49	4,758.00	1,836.51	8.4	219.42	3,132.08
397.35	39735 Comm Eq, ITRON Equipment	1,875,309.16		15-R3	0%	6.67%	125,020.61	196,319.33	403,523.00	207,203.67	11.7	17,709.72	142,730.33
	TOTAL General Equipment	3,585,147.95				7.32%	262,272.72	1,550,428.01	1,432,276.00	-118,152.01		-35,729.16	226,543.56
	TOTAL Depreciable Plant	99,735,941.90				2.76%	2,751,372.11	26,366,002.52	28,375,766.00	2,009,763.48		16,119.95	2,767,492.06
	NON-DEPRECIABLE PLANT												
	NON-DEPRECIABLE												
365.00	(13072) Rights of Way	0.00											
374.40	37440 Land Rgts, Other Distr Sys	89,408.82											
374.50	37450 Rights of Way	17,910.67											
389.00	(13073) General and Miscellaneous Land	232,946.85											
	Total Land	340,266.34											
	INTANGIBLE PLANT												
303.00	(13030) Miscellaneous Intangible Plant	2,328,373.75											
304.00	(13040) Land Rights	6,816.33											
	Total Intangible Plant	2,335,190.08											
386.20													
386.30	38630 Diamond Boiler	1,148,341.31											
	TOTAL Non-Depreciable Plant	3,823,797.73											
	TOTAL Plant in Service	103,559,739.63											

(1) Life Span Method Utlized. Interim Retirement Rate. Service Lives Vary.
(2) Adjusted for Estimated Future Net Salvage Account 392 Is Currently Fully Depreciated.
No Further Depreciation Should Be Accrued At The Present Time.

Table 2-WL-Gross Salvage

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	(d)	A.S.L./ Survivor Curve (e)	Gross Salvage % (f)	Annual Depr. Rate - % (g)	Annual Depreciation Expense (h)	Gross Salvage Book Depreciation Reserve (i)	Gross Salvage Theoretical Depreciation Reserve (j)	Theor. Reserve Over (Under) Book Reserve (k)	Average Remaining Life (l)	Annual Resr. Variance Amortization (m)	Total Annual Depr Expense Plus Resrv. Amort. (n)
	DEPRECIABLE PLANT												
	Structures												
305.00	(13081) Production Plant Structures	80,968.05	(1)	No Int	0%	0.00%	0.00	0.00	0.00	0.00	1.1	0.00	0.00
375.20	366.00 Str, City Gate Mea & Reg	48,195.00	(1)	80-L0	0%	0.00%	0.00	0.00	0.00	0.00	31.1	0.00	0.00
375.70	390.00(13086) Distribution System Struct	2,286,937.84	(1)	80-L0	0%	0.00%	0.00	-148,546.12	0.00	148,546.12	23.7	6,267.77	6,267.77
	TOTAL Structures	2,416,100.89				0.00%	0.00	-148,546.12	0.00	148,546.12		6,267.77	6,267.77
	Production Equipment												
311.00	(13210) Other Gas Generating Equipment	373,861.73	(1)	No Int	0%	0.00%	0.00	0.00	0.00	0.00	0.5	0.00	0.00
320.00	(13300) Other Production Equipment	7,640.16		20-R4	0%	0.00%	0.00	0.00	0.00	0.00	7.4	0.00	0.00
321.00	(13300) LNG Equipment	56,860.76		20-R5	0%	0.00%	0.00	0.00	0.00	0.00	6.8	0.00	0.00
	TOTAL Production Equipment	438,362.65				0.00%	0.00	0.00	0.00	0.00		0.00	0.00
	Distribution Equipment												
	MAINS												
376.20	(13564) Steel Mains (Coated & Wrapped)	15,171,551.64		45-R3	0%	0.00%	0.00	0.00	0.00	0.00	31.8	0.00	0.00
376.30	(13566) Steel Mains (Bare)	410,240.41		31-L3	0%	0.00%	0.00	0.00	0.00	0.00	6.5	0.00	0.00
376.40	(13567) Plastic Mains	37,913,691.18		45-S2	0%	0.00%	0.00	0.00	0.00	0.00	34.7	0.00	0.00
376.50	(13562) Joint Clamps	559,872.74		15-S6	0%	0.00%	0.00	0.00	0.00	0.00	6.1	0.00	0.00
376.60	(13565) Cathodic Protection	308,767.26		18-R5	0%	0.00%	0.00	0.00	0.00	0.00	10.8	0.00	0.00
376.80	(13561) Cast Iron Mains	87,713.39		62-S5	0%	0.00%	0.00	0.00	0.00	0.00	5.9	0.00	0.00
	Total Mains	54,451,836.62				0.00%	0.00	0.00	0.00	0.00		0.00	0.00
378.20	369.00 (13580) Pumping and Regulating Eq.	1,953,245.39		30-R3	0%	0.00%	0.00	0.00	0.00	0.00	20.6	0.00	0.00
	SERVICES												
380.10	(13591) Bare Steel	204,647.36		47-R3	0%	0.00%	0.00	0.00	0.00	0.00	11.1	0.00	0.00
380.20	(13592) Coated Steel Not Wrapped	253,890.14		38-L3	0%	0.00%	0.00	0.00	0.00	0.00	12.3	0.00	0.00
380.30	(13593) Steel Coated & Wrapped	142,123.50		38-R1.5	0%	0.00%	0.00	0.00	0.00	0.00	18.3	0.00	0.00
380.40	(13594) Plastic	23,317,516.88		40-R3	0%	0.00%	0.00	0.00	0.00	0.00	29.3	0.00	0.00
	Total Services	23,918,177.88				0.00%	0.00	0.00	0.00	0.00		0.00	0.00
381.00	(13600) Customers' Meters	2,432,022.55		30-R5	0%	0.00%	0.00	0.00	0.00	0.00	13.5	0.00	0.00
382.00	(13600) Customers' Meters Installations	9,196,255.72		32-R4	0%	0.00%	0.00	0.00	0.00	0.00	23.2	0.00	0.00
383.00	(13600) Gas Regulators	185,195.22		30-R3	0%	0.00%	0.00	0.00	0.00	0.00	25.2	0.00	0.00
386.10/.20	(13610) Misc. Prop on Cust. Prem-WH & CB	1,159,597.03		10-R1.5	5%	-0.50%	-5,797.99	-126,247.78	-28,088.00	98,159.78	5.2	18,876.88	13,078.89
	TOTAL Distribution Equipment	93,296,330.41				-0.01%	-5,797.99	-126,247.78	-28,088.00	98,159.78		18,876.88	13,078.89

Table 2-WL-Gross Salvage

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	(d)	A.S.L./ Survivor Curve (e)	Gross Salvage % (f)	Annual Depr. Rate - % (g)	Annual Depreciation Expense (h)	Gross Salvage Book Depreciation Reserve (i)	Gross Salvage Theoretical Depreciation Reserve (j)	Theor. Reserve Over (Under) Book Reserve (k)	Average Remaining Life (l)	Annual Resr. Variance Amortization (m)	Total Annual Depr Expense Plus Reserv. Amort. (n)
	General Equipment												
	OFFICE EQUIPMENT												
391.10	39110 OF&E, Unspecified	556,427.93		11-S3	2%	-0.18%	-1,011.69	-11,164.48	-8,323.00	2,841.48	2.8	1,025.81	14.12
391.11	39111 OF&E, Data Handling Equip	7,565.50		10-R4	0%	0.00%	0.00	0.00	0.00	0.00	7.5	0.00	0.00
391.12	(13721) Information System	123,869.53		8-L4	0%	0.00%	0.00	0.00	0.00	0.00	5.5	0.00	0.00
	Total Office Furniture & Equipment	687,862.96				-0.15%	-1,011.69	-11,164.48	-8,323.00	2,841.48		1,025.81	14.12
392.00	(13730) Transportation Equipment	38,676.09		9-L4	10%	0.00%	0.00	-7,647.94	-3,139.00	4,508.94	1.7	0.00	0.00 (2)
393.00	(13740) Stores Equipment	31,519.95		13-L5	0%	0.00%	0.00	0.00	0.00	0.00	1.8	0.00	0.00
394.10	387.00 Tools, Garage & Service Eq	438,189.86		19-R5	2%	-0.11%	-461.25	-14,897.69	-5,087.00	9,810.69	8.0	1,230.95	769.70
394.30	39400 Tools, Tools & Other	87,971.27		18-R5	2%	-0.11%	-97.75	0.00	-543.00	-543.00	12.4	-43.79	-141.54
396.00	39600 Power Operated Equipment	75,266.49		15-R4	10%	-0.67%	-501.78	0.00	-6,036.00	-6,036.00	3.0	-2,032.32	-2,534.10
397.00	39700 Communication Equipment	321,225.57		10-L3	0%	0.00%	0.00	-4,028.46	0.00	4,028.46	8.3	488.30	488.30
397.25	39725 Comm Eq, Metscan/Telemetering	29,126.60		10-R3	0%	0.00%	0.00	0.00	0.00	0.00	8.4	0.00	0.00
397.35	39735 Comm Eq, ITRON Equipment	1,875,309.16		15-R3	0%	0.00%	0.00	0.00	0.00	0.00	11.7	0.00	0.00
	TOTAL General Equipment	3,585,147.95				-0.06%	-2,072.47	-37,738.58	-23,128.00	14,610.58		668.94	-1,403.53
	TOTAL Depreciable Plant	99,735,941.90				-0.01%	-7,870.46	-312,532.48	-51,216.00	261,316.48		25,813.59	17,943.13
	NON-DEPRECIABLE PLANT												
	NON-DEPRECIABLE												
365.00	(13072) Rights of Way	0.00											
374.40	37440 Land Rgts, Other Distr Sys	89,408.82											
374.50	37450 Rights of Way	17,910.67											
389.00	(13073) General and Miscellaneous Land	232,946.85											
	Total Land	340,266.34											
	INTANGIBLE PLANT												
303.00	(13030) Miscellaneous Intangible Plant	2,328,373.75											
304.00	(13040) Land Rights	6,816.33											
	Total Intangible Plant	2,335,190.08											
386.20													
386.30	38630 Diamond Boiler	1,148,341.31											
	TOTAL Non-Depreciable Plant	3,823,797.73											
	TOTAL Plant in Service	103,559,739.63											

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.
(2) Adjusted for Estimated Future Net Salvage Account 392 Is Currently Fully Depreciated.
No Further Depreciation Should Be Accrued At The Present Time.

Table 2-WL-COR

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No.	Description	Original Cost 12-31-2006		A.S.L./ Survivor Curve	COR %	Annual Depr. Rate - %	Annual Depreciation Expense	COR Book Depreciation Reserve	COR Theoretical Depreciation Reserve	Theor. Reserve Over (Under) Book Reserve	Average Remaining Life	Annual Resr. Variance Amortization	Total Annual Depr Expense Plus Resrv. Amort.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	DEPRECIABLE PLANT												
	Structures												
305.00	(13081) Production Plant Structures	80,968.05	(1)	No Int	-5%	0.41%	329.14	3,823.91	3,679.00	-144.91	1.1	-131.73	197.41
375.20	366.00 Str, City Gate Mea & Reg	48,195.00	(1)	80-L0	-5%	0.14%	65.63	-614.88	372.00	986.88	31.1	31.78	97.41
375.70	390.00(13086) Distribution System Struct	2,286,937.84	(1)	80-L0	0%	0.00%	0.00	0.00	0.00	0.00	23.7	0.00	0.00
	TOTAL Structures	2,416,100.89				0.02%	394.77	3,209.03	4,051.00	841.97		-99.95	294.82
	Production Equipment												
311.00	(13210) Other Gas Generating Equipment	373,861.73	(1)	No Int	-10%	0.42%	1,565.59	36,590.50	36,604.00	13.50	0.5	27.00	1,592.59
320.00	(13300) Other Production Equipment	7,640.16		20-R4	0%	0.00%	0.00	0.00	0.00	0.00	7.4	0.00	0.00
321.00	(13300) LNG Equipment	56,860.76		20-R5	0%	0.00%	0.00	0.00	0.00	0.00	6.8	0.00	0.00
	TOTAL Production Equipment	438,362.65				0.36%	1,565.59	36,590.50	36,604.00	13.50		27.00	1,592.59
	Distribution Equipment												
	MAINS												
376.20	(13564) Steel Mains (Coated & Wrapped)	15,171,551.64		45-R3	-25%	0.56%	84,288.40	1,023,407.15	1,109,312.00	85,904.85	31.8	2,701.41	86,987.81
376.30	(13566) Steel Mains (Bare)	410,240.41		31-L3	-25%	0.81%	3,308.39	74,960.43	81,253.00	6,292.57	6.5	966.60	4,274.99
376.40	(13567) Plastic Mains	37,913,691.18		45-S2	-25%	0.56%	210,631.62	1,995,701.50	2,163,221.00	167,519.50	34.7	4,827.65	215,459.27
376.50	(13562) Joint Clamps	559,872.74		15-S6	-25%	1.67%	9,331.21	24,186.17	83,552.00	59,365.83	6.1	9,732.10	19,063.31
376.60	(13565) Cathodic Protection	308,767.26		18-R5	-25%	1.39%	4,288.43	28,380.91	30,763.00	2,382.09	10.8	220.56	4,508.99
376.80	(13561) Cast Iron Mains	87,713.39		62-S5	-25%	0.40%	353.68	18,302.86	19,839.00	1,536.14	5.9	259.92	613.60
	Total Mains	54,451,836.62				0.57%	312,199.73	3,164,939.02	3,487,940.00	323,000.98		18,708.25	330,907.98
378.20	369.00 (13580) Pumping and Regulating Eq.	1,953,245.39		30-R3	-5%	0.17%	3,255.41	40,158.88	30,507.00	-9,651.88	20.6	-468.54	2,786.87
	SERVICES												
380.10	(13591) Bare Steel	204,647.36		47-R3	-85%	1.81%	3,701.07	84,295.84	140,614.00	56,318.16	11.1	5,073.71	8,774.78
380.20	(13592) Coated Steel Not Wrapped	253,890.14		38-L3	-85%	2.24%	5,679.12	92,352.24	154,053.00	61,700.76	12.3	5,016.32	10,695.44
380.30	(13593) Steel Coated & Wrapped	142,123.50		38-R1.5	-85%	2.24%	3,179.08	39,566.39	66,001.00	26,434.61	18.3	1,444.51	4,623.59
380.40	(13594) Plastic	23,317,516.88		40-R3	-85%	2.13%	495,497.23	3,337,103.24	5,566,630.00	2,229,526.76	29.3	76,093.06	571,590.29
	Total Services	23,918,177.88				2.12%	508,056.50	3,553,317.71	5,927,298.00	2,373,980.29		87,627.61	595,684.11
381.00	(13600) Customers' Meters	2,432,022.55		30-R5	0%	0.00%	0.00	0.00	0.00	0.00	13.5	0.00	0.00
382.00	(13600) Customers' Meters Installations	9,196,255.72		32-R4	-10%	0.31%	28,738.30	242,169.97	251,388.00	9,218.03	23.2	397.33	29,135.63
383.00	(13600) Gas Regulators	185,195.22		30-R3	0%	0.00%	0.00	0.00	0.00	0.00	25.2	0.00	0.00
386.10/.20	(13610) Misc. Prop on Cust. Prem-WH & CB	1,159,597.03		10-R1.5	0%	0.00%	0.00	0.00	0.00	0.00	5.2	0.00	0.00
	TOTAL Distribution Equipment	93,296,330.41				0.91%	852,249.94	7,000,585.58	9,697,133.00	2,696,547.42		106,264.65	958,514.59

Table 2-WL-COR

Northern Utilities, Inc.
New Hampshire

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Straight Line/Whole Life Depreciation Method and Technique
Plus Amortization of Book Versus Therorectical Depreciation Reserve Variance Over Average Remaining Lives as of December 31, 2006

Account No. (a)	Description (b)	Original Cost 12-31-2006 (c)	(d)	A.S.L./ Survivor Curve (e)	COR % (f)	Annual Depr. Rate - % (g)	Annual Depreciation Expense (h)	COR Book Depreciation Reserve (i)	COR Theoretical Depreciation Reserve (j)	Theor. Reserve Over (Under) Book Reserve (k)	Average Remaining Life (l)	Annual Resr. Variance Amortization (m)	Total Annual Depr Expense Plus Resrv. Amort. (n)
	General Equipment												
	OFFICE EQUIPMENT												
391.10	39110 OF&E, Unspecified	556,427.93		11-S3	0%	0.00%	0.00	0.00	0.00	0.00	2.8	0.00	0.00
391.11	39111 OF&E, Data Handling Equip	7,565.50		10-R4	0%	0.00%	0.00	0.00	0.00	0.00	7.5	0.00	0.00
391.12	(13721) Information System	123,869.53		8-L4	0%	0.00%	0.00	0.00	0.00	0.00	5.5	0.00	0.00
	Total Office Furniture & Equipment	687,862.96				0.00%	0.00	0.00	0.00	0.00		0.00	0.00
392.00	(13730) Transportation Equipment	38,676.09		9-L4	0%	0.00%	0.00	0.00	0.00	0.00	1.7	0.00	0.00 (2)
393.00	(13740) Stores Equipment	31,519.95		13-L5	0%	0.00%	0.00	0.00	0.00	0.00	1.8	0.00	0.00
394.10	387.00 Tools, Garage & Service Eq	438,189.86		19-R5	0%	0.00%	0.00	0.00	0.00	0.00	8.0	0.00	0.00
394.30	39400 Tools, Tools & Other	87,971.27		18-R5	0%	0.00%	0.00	0.00	0.00	0.00	12.4	0.00	0.00
396.00	39600 Power Operated Equipment	75,266.49		15-R4	0%	0.00%	0.00	0.00	0.00	0.00	3.0	0.00	0.00
397.00	39700 Communication Equipment	321,225.57		10-L3	0%	0.00%	0.00	0.00	0.00	0.00	8.3	0.00	0.00
397.25	39725 Comm Eq, Metscan/Telemetering	29,126.60		10-R3	0%	0.00%	0.00	0.00	0.00	0.00	8.4	0.00	0.00
397.35	39735 Comm Eq, ITRON Equipment	1,875,309.16		15-R3	0%	0.00%	0.00	0.00	0.00	0.00	11.7	0.00	0.00
	TOTAL General Equipment	3,585,147.95				0.00%	0.00	0.00	0.00	0.00		0.00	0.00
	TOTAL Depreciable Plant	99,735,941.90				0.86%	854,210.30	7,040,385.11	9,737,788.00	2,697,402.89		106,191.70	960,402.00
	NON-DEPRECIABLE PLANT												
	NON-DEPRECIABLE												
365.00	(13072) Rights of Way	0.00											
374.40	37440 Land Rgts, Other Distr Sys	89,408.82											
374.50	37450 Rights of Way	17,910.67											
389.00	(13073) General and Miscellaneous Land	232,946.85											
	Total Land	340,266.34											
	INTANGIBLE PLANT												
303.00	(13030) Miscellaneous Intangible Plant	2,328,373.75											
304.00	(13040) Land Rights	6,816.33											
	Total Intangible Plant	2,335,190.08											
386.20													
386.30	38630 Diamond Boiler	1,148,341.31											
	TOTAL Non-Depreciable Plant	3,823,797.73											
	TOTAL Plant in Service	103,559,739.63											

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.
(2) Adjusted for Estimated Future Net Salvage Account 392 Is Currently Fully Depreciated. No Further Depreciation Should Be Accrued At The Present Time.

Section 3

NORTHERN UTILITIES, INC.
New Hampshire

General

This report sets forth the results of our study of the depreciable property of the Northern Utilities, Inc. - New Hampshire (the Company) as of December 31, 2006 and contains the basic parameters (recommended average service lives and life characteristics) for the proposed average remaining life depreciation rates until a subsequent service life study is completed. All average service lives set forth in this report are developed based upon plant in service as of December 31, 2006.

The scope of the study included an analysis of Company historical data through December 31, 2006, discussions with Company management staff to identify prior and prospective factors affecting the Company's plant in service, as well as interpretation of past service life data experience and future life expectancies to determine the appropriate average service lives of the Company's surviving plant.

The study utilized the resulting average service lives, along with the results of our salvage analysis, and the Company's account level vintaged plant in service investment to develop the resulting recommended average service life depreciation rates and depreciation expense related to the Company's plant in service as of December 31, 2006. Furthermore, the depreciation study analysis also used the company's book depreciation reserve and resulting theoretical depreciation reserve, from the proposed life and salvage factors to identify the variance between the book depreciation reserve and calculated theoretical depreciation reserve.

Each identified account level depreciation reserve variance was used together the with applicable account level average remaining life to develop the required level of annual amortization to be recovered over the property group's average remaining life. The required level of annual depreciation expense is then the sum of the calculated annual depreciation expense using the proposed Broad Group/Whole Life depreciation rates with the applicable plant in service balance plus the annual amortization of the depreciation reserve balance variance.

In preparing the study, the Company's historical investment data were studied using various service life analysis techniques. Further, discussions were held with the Company's management to obtain an overview of the Company's facilities and to discuss the general scope of operations together with other factors which could have a bearing on the service lives of the Company's property. Finally, the study results were tempered by information gathered during plant inspection tours of a representative portion of the Company's property.

The Company maintains a property record containing a summary of its fixed capital investments by property account. This investment data was analyzed and summarized by property group and/or sub group and vintage then utilized as a basis for the various depreciation calculations.

Depreciation Study Overview

There are numerous methods utilized to recover property investment depending upon the goal. For example, accelerated methods such as double declining balance and sum of years digits are methods used in tax accounting to motivate additional investments. Broad Group (BG) and Equal Life Group (ELG) are both Straight Line Grouping Procedures recognized and utilized by various regulatory jurisdictions depending upon the policy of the specific agency.

The Straight Line (Group) Method of depreciation utilized in this study to develop the recommended depreciation rates is the Broad Group Procedure together with the Whole Life Technique. In addition to the Whole Life based depreciation rates, Tables 1 and 2 in Section 2 of this report also include the development of an annual reserve variance amortization. The use of this procedure and technique is based upon recovering the net book cost (original cost less book reserve) of the surviving plant in service over its estimated remaining useful life. Any variance between the book reserve and an implied theoretical calculated reserve is compensated for under this procedure. That is, as the Company's book reserve increases above or declines below the theoretical reserve at a specific point in time, the Company's whole life depreciation rate and reserve variance, in subsequent years, will be increased or decreased to compensate for the variance, thereby, enabling full recovery of the Company's investment by the end of the property's life.

The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The annual depreciation amount to be utilized is based upon the remaining productive life over which the undepreciated capital investment needs to be recovered. The determination of the productive remaining life for each property group usually includes an in-depth study of past experience in addition to estimates of future expectations.

Annual Depreciation Accrual

Through the utilization of the Whole Life Technique and depreciation reserve variance amortization, the Company will recover the undepreciated fixed capital investment in the appropriate amounts as annual depreciation expense in each year throughout the remaining life of the property. The procedure incorporates the future life expectancy of the property, the vintaged surviving plant in service, and estimated net salvage, together with the book depreciation reserve balance to develop the annual depreciation rate for each property account. Accordingly, the process used per this study meets the objective of providing a straight line recovery of the undepreciated fixed capital property investment.

As indicated, the use of the proposed depreciation approach results in charging the appropriate annual depreciation amounts over the remaining life of the property to insure full recovery by end of life. That does not mean that once an average remaining life is estimated, it can not be changed at any point throughout the service life, but that the annual expense is calculated on a Straight Line Method rather than by the previously mentioned, "sum of the years digits" or "double declining balance" methods, etc. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one depreciable group or plant account rather than calculating depreciation for each individual unit.

Under Broad Group depreciation some units may be over depreciated and other units may be under depreciated at the time when they are retired from service, but overall, the account is fully depreciated when average service life is attained. By comparison, Equal Life Group depreciation rates are designed to fully accrue the cost of the asset group by the time of retirement. For both the Broad Group and Equal Life Group Procedures the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption the retired property was at average service life.

Group Depreciation Procedures

Group depreciation procedures are utilized to depreciate property when more than one item of property is being depreciated. Such a procedure is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing a group depreciation procedure allows for a condensed application of depreciation rates to groups of similar property in lieu of extensive depreciation calculations on an item by item basis. The two more common group depreciation procedures are the Broad Group (BG) and Equal Life Group (ELG) approach.

In developing depreciation rates using the Broad Group procedure, the annual depreciation rate is based on the average of the overall group, which is then applied to the group's surviving original cost investment. A characteristic of this procedure is that retirements of individual units occurring prior to average service life will be under depreciated, while individual units retired after average service life will be over depreciated when removed from service, but overall, the group investment will achieve full recovery by the end of the life of the total property group. That is, the under recovery occurring early in the life of the account is balanced by the over recovery occurring subsequent to average service life. In summary, the cost of the investment is complete at the end of the property's life cycle, but the rate of recovery does not match the consumption pattern which was used to provide service to the company's customers.

Under the average service life procedure, the annual depreciation rate is calculated by the following formula:

$$\text{Annual Accrual Rate, Percent} = \frac{100\% - \text{Salvage}}{\text{Average Service Life}} \times 100$$

The application of the broad group procedure to life span groups results in each vintage investment having a different average service life. This circumstance exists because the concurrent retirement of all vintages at the anticipated retirement year results in truncating and, therefore, restricting the life of each successive years vintage investment. An average service life is calculated for each vintage investment in accordance with the above formula. Subsequently, a composite service life and depreciation rate is calculated relative to all vintages within the property group by weighting the life for each vintage by the related surviving vintage investment within the group.

In the Equal Life Group, the property group is subdivided, through the use of plant life tables, into equal life groups. In each equal life group, portions of the overall property group includes that portion which experiences the life of the specific sub-group. The relative size of each sub-group is determined from the overall group life characteristic (property dispersion curve). This procedure both overcomes the disadvantage of voluminous record requirements of unit depreciation, as well as, eliminates the need to base depreciation on overall lives as required under the broad group procedure. The application of this procedure results in each sub-group of the property having a single life. In this procedure, the full cost of short lived units is accrued during their lives leaving no under accruals to be recovered by over accruals on long lived plant. The annual depreciation for the group is the summation of the depreciation accruals based on the service life of each Equal Life Group.

The ELG Procedure is superior to the BG Procedure because it allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are more appropriately charged with the cost of the property consumed in providing them service during the applicable service period. The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby, not only reducing the risk of incomplete cost recovery, but also the procedure results in less return on rate base over the life of a depreciable group. The total depreciation expense is the same for all procedures which allocate the full capital cost to expense, but at any specific point in time, the depreciated original cost is less under the ELG procedure than under the BG procedure. This circumstance exists because under the equal life group procedure, the rate base is not maintained at a level of greater than the future service value of the surviving plant as is the case when using the average service life procedure. Consequently, the total return required from the ratepayers is less under the ELG procedure.

While the equal life group procedure has been known to depreciation experts for many years widespread interest in applying the procedure developed only after high speed electronic computers became available to perform the large volume of arithmetic computations required in developing ELG based depreciation lives and rates. The table on the following page illustrates the procedure for calculating equal life group depreciation accrual rates and summarizes the results of the underlying calculations. Depreciation rates are determined for each age interval (one year increment) during the life of a group of property which was installed in a given year or vintage group. The age of the vintage group is shown in column (A) of the ELG table. The percent surviving at the beginning of each age interval is determined from the Iowa 10-R3 survivor curve which is set forth in column

XYZ UTILITY COMPANY
CALCULATION OF ASL, ARL AND ACCRUED DEPRECIATION FACTORS
BASED UPON AN IOWA 10-R3 CURVE USING THE EQUAL LIFE GROUP (ELG) PROCEDURE

							EQUAL LIFE GROUP PROCEDURE			
AGE AT BEGIN OF INTERVAL	LIFE TABLE BEGIN OF INTERVAL	RETIREMENT DURING INTERVAL	AVERAGE SURVIVING	AGE OF AMOUNT RETIRED	AMOUNT FOR EACH LIFE GROUP	AMOUNT FOR REMAINING LIFE GROUPS	AVERAGE SERVICE LIFE	AVERAGE REMAINING LIFE	ELG/ARL DEPR RATE	ACCRUED DEPR RES FACTOR
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
0.0	1.0000000	0.0009198	0.9995401	0.25	0.0009198	0.0583036	8.57	8.57	11.67	0.0000000
0.5	0.9990802	0.0033314	0.9974145	1.0	0.0033314	0.1131019	8.82	8.32	11.34	0.0586875
1.5	0.9957488	0.0065393	0.9924792	2.0	0.0032697	0.1098013	9.04	7.54	11.06	0.1659501
2.5	0.9892095	0.0117037	0.9833577	3.0	0.0039012	0.1062159	9.26	6.76	10.80	0.2700337
3.5	0.9775058	0.0193690	0.9678213	4.0	0.0048422	0.1018442	9.50	6.00	10.52	0.3683062
4.5	0.9581368	0.0300339	0.9431199	5.0	0.0060068	0.0964196	9.78	5.28	10.22	0.4600565
5.5	0.9281029	0.0442969	0.9059545	6.0	0.0073828	0.0897248	10.10	4.60	9.90	0.5447146
6.5	0.8838060	0.0631367	0.8522377	7.0	0.0090195	0.0815287	10.45	3.95	9.57	0.6217794
7.5	0.8206693	0.0876232	0.7768577	8.0	0.0109529	0.0715375	10.86	3.36	9.21	0.6906424
8.5	0.7330461	0.1166879	0.6747022	9.0	0.0129653	0.0595783	11.32	2.82	8.83	0.7505770
9.5	0.6163582	0.1431836	0.5447664	10.0	0.0143184	0.0459365	11.86	2.36	8.43	0.8010714
10.5	0.4731746	0.1533568	0.3964962	11.0	0.0139415	0.0318066	12.47	1.97	8.02	0.8423003
11.5	0.3198178	0.1363216	0.2516570	12.0	0.0113601	0.0191557	13.14	1.64	7.61	0.8753616
12.5	0.1834962	0.0975199	0.1347363	13.0	0.0075015	0.0097249	13.85	1.35	7.22	0.9022159
13.5	0.0859763	0.0559043	0.0580242	14.0	0.0039932	0.0039775	14.59	1.09	6.85	0.9254232
14.5	0.0300720	0.0244398	0.0178521	15.0	0.0016293	0.0011663	15.31	0.81	6.53	0.9473077
15.5	0.0056322	0.0055324	0.0028660	16.0	0.0003458	0.0001788	16.03	0.53	6.24	0.9667657
16.5	0.0000998	0.0000998	0.0000499	17.0	0.0000059	0.0000029	17.00	0.50	5.88	0.9705882
17.5	0.0000000	0.0000000	0.0000000	18.0	0.0000000	0.0000000				
		1.0000000				1.0000000				

Table 3

(B). The percent retired during each age interval, as shown in column (C), is the difference between the percent surviving at successive age intervals. Accordingly, the percentage amount of the vintage group retired defines the size of each equal life group. For example, during the interval 3 ½ to 4 ½, 1.93690 percent of the vintage group is retired at an average age of four years. In this case, the 1.93690 percent of the group experiences an equal life of four years. Likewise, 3.00339 percent is retired during the interval 4 ½ to 5 ½ and experiences a service life of five years. Further, 4.42969 percent experiences a six-year life; etc. Calculations are made for each age interval from the zero age interval through the end of the life of the vintage group. The average service life for each age interval's equal life group is shown in column (E) of the table.

The amount to be accrued annually for each equal life group is equal to the percentage retired in the equal life group divided by its service life. Inasmuch as additions and retirements are assumed, for calculation purposes, to occur at midyear only one-half of the equal life group's annual accrual is allocated to expense during its first and last years of service life. The accrual amount for the property retired during age interval 0 to ½ must be equal to the amount retired to insure full recovery of that component during that period. The accruals for each equal life group during the age intervals of the vintage group's life cycle are shown in column (F). The total accrual for a given year is the summation of the equal life group accruals for that year. For example, the total accrual for the second year, as shown in column (G), is 11.31019 percent and is the sum of all succeeding years remaining equal life group accruals plus one half of the current years life group accrual listed in column (F). For the zero age interval year, the total accrual is equal to one half of the sum of all succeeding years remaining equal life accruals plus the amount for the zero interval equal life group accrual. The one half year accrual for the zero age interval is consistent with the half year convention relative to property during its installation year. The sum of the annual accruals for each age interval contained in column (G) total to 1.000 demonstrating that the developed rates will recover 100% of plant no more and no less. The annual accrual rate which will result in the accrual amount is the ratio of the accrual amount (11.31019 percent) to the average percent surviving during the interval, column (D), (99.74145 percent), which is a rate of 11.34% (column J). Column (J) contains a summary of the accrual rates for each age interval of the property groups life cycle based upon an Iowa 10-R3 survivor curve.

<u>Whole Life Technique</u>

In the Whole Life Technique, the annual accrual is calculated according to the formula where, (A) the annual depreciation for each group equals, (D) the depreciable cost of plant, less (S) the estimated net salvage, divided by (ASL) the composite average service life of the group:

$$A = \frac{D - S}{ASL}$$

The annual accrual rate (a) is expressed as a percentage of the depreciable plant balance by dividing the equation by (D) the depreciable cost of plant:

$$a = \frac{D - S}{ASL} \times \frac{1}{D} \times 100$$

<u>Remaining Life Technique</u>

In the Average Remaining Life depreciation technique, the annual accrual is calculated according to the following formula where, (A) the annual depreciation for each group equals, (D) the depreciable cost of plant, less (U) the accumulated provision for depreciation, less (S) the estimated future net salvage, divided by (R) the composite remaining life of the group:

$$A = \frac{D - U - S}{R}$$

The annual accrual rate (a) is expressed as a percentage of the depreciable plant balance by dividing the equation by (D) the depreciable cost of plant times 100:

$$(a) = \frac{D - U - S}{R} \times \frac{1}{D} \times 100$$

As further indicated by the equation, the accumulated provision for depreciation by vintage is required in order to calculate the remaining life depreciation rate for each property group. In practice, most often such detail is not available; therefore, composite remaining lives are determined for each depreciable group, i.e., property account.

The remaining life for a depreciable group is calculated by first determining the remaining life for each vintage year in which there is surviving investment. This is accomplished by solving the area under the survivor curve selected to represent the average life and life characteristic of the property account. The remaining life for each vintage is composited by dividing (D) the depreciable cost of each vintage, by (L) its average service life, and multiplying this ratio by its average remaining life (E). The composite remaining life of the group (R) equals the sums of products divided by the sum of the quotients:

$$R\ Group = \sum \underline{D/L \times E}$$

$$\sum D/L$$

The functional level accumulated provision for depreciation, which was the basis for developing the composite average remaining life accrual and annual depreciation rate for each property account is obtained from the Company's books and records. Where required, the functional level depreciation reserve is further allocated to each property account and sub-account based upon a detailed theoretical depreciation reserve.

Salvage

Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Salvage experience is normally included with the depreciation rate so that current accounting periods reflect a proportional share of the ultimate abandonment and removal cost or salvage received at the end of the property service life. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage.

The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise removing plant, as well as normal environmental clean up costs associated with the property. Salvage includes proceeds received for the sale of plant and materials or the return of equipment to stores for reuse.

Net salvage experience is studied for a period of years to determine the trends which have occurred in the past. These trends are considered together with any changes that are anticipated in the future to determine the future net salvage factor for remaining life depreciation purposes. The net salvage percentage is determined by relating the total net positive or negative salvage to the book cost of the property investment.

Service Lives

Several factors contribute to the length of time or average service life which the property achieves. The three (3) major categories under which these factors fall are: (1) physical; (2) functional, and; (3) contingent casualties.

The physical category includes such things as deterioration, wear and tear and the action of the natural elements. The functional category includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute of superior performance. The remaining factor of contingent casualties relates to retirements caused by accidental damage or construction activity of one type or another.

In performing the life analysis for any property being studied, both past experience and future expectations must be considered in order to fully evaluate the circumstances which may have a bearing on the remaining life of the property. This ensures the selection of an average service life which best represents the expected life of each property investment.

Survivor Curves

The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry.

The shape of the curves within the Iowa family are dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company data has not completed its life cycle, therefore, the survivor table generated from the Company data is not extended to zero percent surviving. This situation requires an estimate be made with regard to the remaining segment of the property group's life experience. Further, actual Company experience is often erratic, making its utilization for average service life estimating difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Study Procedures

Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical retirements, current and future construction, historical experience and future expectations of salvage and cost of removal as related to plant investment. Service lives are affected by many different factors, some of which can be obtained from studying plant experience, others which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a valuable tool in selecting service lives. In the case where changing technology or a less costly alternative develops, then historical experience is of lesser value.

While various methods are available to study historical data, the principal methods utilized to determine average service lives for a Company's property are the Retirement Rate Method, the Simulated Plant Record Method, the Life Span Method, and the Judgement Method.

Retirement Rate Method - The Retirement Rate Method uses actual Company retirement experience to develop a survivor curve (observed life table) which is used to determine the average service life being experienced in the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band studied, the "observed life table" is constructed based on retirement experience within the band of years. In some cases, the total life of the account has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to a standard Survivor curve. The matching process is performed both by computer analysis, using a least square technique, and by manually plotting observed life tables to which smooth curves are fitted. The fitted smooth curve provides the basis to determine the average service life of the property group under study.

Simulated Balances Method - In this method of analysis, simulated surviving balances are determined for each balance included in the test band by multiplying each proceeding years original gross additions installed by the Company by the appropriate factor of each Standard Survivor Curve, summing the products, and comparing the results with the related year end plant balance to determine the "best fitting" curve and life within the test period. Various test bands are reviewed to determine trends or changes to indicated service lives in various bands of years. By definition, the curve with the "best fit" is the curve which produces simulated plant balances that most closely matches the actual plant balances as determined by the sum of the "least squares". The sum of the "least squares" is arrived at by starting with the difference between the simulated balances and the actual balance for a given year, squaring the difference, and the curve which produces the smallest sum (of squared difference) is judged to be the "best fit".

Period Retirements Method - The application of the Period Retirements Method is similar to the "Simulated Plant Balances" Method, except the procedure utilizes an Standard Survivor Curve and service life to simulate annual retirements instead of balances in performing the "least squares" fitting process during the test period. This procedure does tend to experience wider fluctuations due to the greater variations in level of experienced retirements versus additions and balances thereby producing greater variation in the study results.

Life Span Method - The Life Span or Forecast Method is a method utilized to study various accounts in which the expected retirement dates of specific property or locations can be reasonably estimated. In the Life Span Method, an estimated probable retirement year is determined for each location of the property group. An example of this would be a structure account, in which the various segments of the account are "life spanned" to a probable retirement date which is determined after considering a number of factors, such as management plans, industry standards, the original construction date, subsequent additions, resultant average age and the current - as well as the overall - expected service life of the property being studied. If in the past the property has experienced interim retirements, these are studied to determine an interim retirement rate. Otherwise, interim retirement rate parameters are estimated for properties which are anticipated to experience such retirements. The selected interim service life parameters (Iowa curve and life) are then used with the vintage investment and probable retirement year of the property to determine the average remaining life as of the study date. No attempt is made to include any anticipated additions to the property subsequent to the study date. The recovery of such additions if made, is reflected when preparing subsequent depreciation studies.

Judgement Method - Standard quantitative methods such as the Retirement Rate Method, Simulated Plant Record Method, etc. are normally utilized to analyze a Company's available historical service life data. The results of the analysis together with information provided by management as well as judgement are utilized in estimating the prospective recommended average service lives. However, there are some circumstances where sufficient retirements have not occurred, or where prospective plans or guidelines are unavailable. In these circumstances, judgement alone is utilized to estimate service lives based upon service lives used by other utilities for this class of plant as well as what might be reasonable life for this plant giving consideration to the current age and use of the facilities.

Section 4

Northern Utilities, Inc-New Hampshire

Study Analysis & Results

ACCOUNT – 305.00 Production Plant Structures

Historical Experience

Plant Statistics	Plant Balance = $80,968 Average Age of Survivors = 11.4 years Original Gross Additions = $87,327 Oldest Surviving vintage = 1994 Retirements = $5,101 or 5.8 % of historical additions. Average Age of Retirements = 44.5 years
Historical Experience Bands	N/A - No Interim Retirement Rate

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
N/A	N/A	N/A	N/A

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
N/A	N/A	N/A	N/A

Forecasted Net Salvage: N/A

Future Expectations and Considerations

The average service life for this property group was developed via the application of the Life Span Method. The property location's investment which is located at Barberry lane in Portsmouth was life spanned to an estimated probable retirement date of 2007 (with the exception of the Butler Building and site facilities that will be retained) based upon the current limited use and the expectation of the facility being retired in the near future. No further interim retirements were estimated for this property category.

Life Analysis Method: Retirement Rate Method (Actuarial) – Life Span Method

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ASL/Curve: No Interim Retirement Curve
Net Salv: -5 %

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: None
Net Salv: -5 %

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	8.54 %	11.05 %
Av. Remaining Life	1.1 years	4.5 years
Reserve Amort. Amount	$-2,757	$6,228

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 311.00 Other Gas Generating Equipment

Historical Experience

Plant Statistics	Plant Balance = $373,862 Average Age of Survivors = 25.3 years Original Gross Additions = $388,418 Oldest Surviving vintage = 1967 Retirements = $10,012 or 2.6 % of historical additions. Average Age of Retirements = 6.7 years
Historical Experience Bands	N/A - No Interim Retirement Rate

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
N/A	N/A	N/A	N/A

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
N/A	N/A	N/A	N/A

Forecasted Net Salvage: N/A

Future Expectations and Considerations

The average service life for this property group was developed via the application of the Life Span Method. The property location's investment which is located at Barberry lane in Portsmouth was life spanned to an estimated probable retirement date of 2007 based upon the current limited use and the expectation of the facility being retired in the near future. No further interim retirements were estimated for this property category.

Life Analysis Method: Retirement Rate Method (Actuarial) - Life Span Method

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: No Interim Retirement Curve
Net Salv: -10%

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: None
Net Salv: -10%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	4.61 %	3.00 %
Av. Remaining Life	0.5 years	4.5 years
Reserve Amort. Amount	$-51,719	$11,759

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 320.00 Other Production Equipment

Historical Experience

Plant Statistics	Plant Balance = $7,640 Average Age of Survivors =13.3 years Original Gross Additions = $27,052 Oldest Surviving vintage = 1990 Retirements = $21,671 or 80.1 % of historical additions. Average Age of Retirements = 17.9 years
Historical Experience Bands	1981– 2006 (Full Depth) 20-R4

Net Salvage: (01-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	2001-06
N/A	N/A	N/A	N/A

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
N/A	N/A	N/A	N/A

Forecasted Net Salvage: N/A

Future Expectations and Considerations

The investment in this account is related to a Calibrator dosimeter unit.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 20-R5
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 25-R4
Net Salv: 0%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	5.00%	5.00 %
Av. Remaining Life	7.4 years	7.9 years
Reserve Amort. Amount	$563	$27

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 321.00 LNG Equipment

Historical Experience

Plant Statistics

Plant Balance = $56,861
Average Age of Survivors =19.5 years
Original Gross Additions = $76,457
Oldest Surviving vintage = 1974
Retirements = $19,597 or 25.6 % of historical additions.
Average Age of Retirements = 19.5 years

Historical Experience Bands: 1993 – 2006 (Full Depth) 20-R5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
N/A	N/A	N/A	N/A

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
N/A	N/A	N/A	N/A

Forecasted Net Salvage: N/A

Future Expectations and Considerations

The account investment is related to a portable vaporizer that has be used on limited occasions during earlier years and no use has occurred during more recent years.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 25-R5
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 25-R5
Net Salv: 0%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	5.00%	5.00 %
Av. Remaining Life	6.8 years	8.5 years
Reserve Amort. Amount	$-757	$736

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 375.20 Str, City Gate Meas & Reg

Historical Experience

Plant Statistics

Plant Balance = $48,195
Average Age of Survivors = 8.3 years
Original Gross Additions = $73,948
Oldest Surviving vintage = 1939
Retirements = $25,752 or 34.8 % of historical additions.
Average Age of Retirements = 10.3 years

Historical Retirement Rate Experience Bands: 1981 – 2006 Estimated Interim Retirement Rate 80-L0

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
N/A	N/A	N/A	N/A

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
N/A	N/A	N/A	N/A

Forecasted Net Salvage: N/A

Future Expectations and Considerations

The company has several distribution facilities located throughout its service territory and these facilities have experienced various levels of activity over the account's history. Such activity occurs inasmuch as the company needs to continuously review its operating requirements and upgrade its facilities as required. Giving consideration to the property group's general construction, each property location's investment continues to be life spanned forty (40) years (or a 10 year remaining life for some limited older facility investments) to its applicable probable retirement year.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 60-L0 Interim Retirement Curve
Net Salv: -5 %

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 80-L0
Net Salv: -5 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.86 %	3.00 %
Av. Remaining Life	31.1 years	N/A
Reserve Amort. Amount	$591	$-1,524

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 375.70 Distribution System Structures

Historical Experience

Plant Statistics	Plant Balance = $2,286,938 Average Age of Survivors = 17.1 years Original Gross Additions = $2,333,162 Oldest Surviving vintage = 1988 Retirements = $6,425 or 0.3 % of historical additions. Average Age of Retirements = 7.5 years
Historical Retirement Rate Experience Bands	1991 – 2006 Estimated Interim Retirement Rate 80-L0

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
N/A	N/A	N/A	N/A

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
N/A	N/A	N/A	N/A

Forecasted Net Salvage: N/A

Future Expectations and Considerations

The company's investment in this account is related to the company's distribution office located in Portsmouth. The investment was life spanned forty-five (45) years from its initial construction date. Given its relatively young age of this property account, only limited amount of interim retirements have occurred to date. As the property continues to age increased amount of interim retirements are anticipated relative to required upgrades and operating changes over time within the facility.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 80-L0 Interim Retirement Curve
Net Salv: 25 %

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 80-L0
Net Salv: 0 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.63 %	1.95 %
Av. Remaining Life	23.7 years	24.5 years
Reserve Amort. Amount	$4,945	$-38,678

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.20 Coated & Wrapped Steel Mains

Historical Experience

Plant Statistics	Plant Balance = $15,171,552 Average Age of Survivors = 14.1 years Original Gross Additions = $16,076,403 Oldest Surviving Vintage = 1966 Retirements = $496,983, or 3.1 % of historical additions. Average Age of Retirements = 15.4 years
Historical Retirement Rate Experience Bands	1991 – 2006 (Full Depth) 45-R3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-16%	-7%	-3%	-17%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -56%

Future Expectations and Considerations

The investment in gas mains is related to several types of pipe, as well as other appurtenant equipment. Accordingly, the investment in the account has been segmented into six (6) sub-account categories which include Cast Iron Mains, Joint Clamps, Steel Mains - Coated and Wrapped, Cathodic Protection, Steel Mains - Bare, and Plastic Mains. The various types of material components within the account represent the fact that the Company has generally installed different materials at various points throughout the history of the account. For example, Cast Iron Mains were principally installed beginning during the early 1900's (presently only a limited amount of Cast Iron remains in service); Bare Steel Mains were installed since the early 1900's through the early 1960's; Coated and Wrapped Steel Mains were installed from the early 1960's and continues through present day. During more recent times beginning with the early 1970's, through the present day, the Company has principally been installing a significant portion of its mains using plastic pipe. Also, beginning with the early 1970's and through recent years, the Company has been installing joint seals on its cast iron pipes to repair joint leaks and as well as to prevent joint leaks. Many of the earlier Joint Seals have since been retired along with the replaced Cast Iron pipe. In conjunction with its Coated and Wrapped Steel Mains, the Company has historical installed cathodic protection to prevent damages caused by corrosion.

As of December 31, 2006 the Company has approximately 465 miles of distribution main in service. Of the miles of Mains currently in service the majority of the Mains are of 4 Inch or smaller diameter. That is, more than 70.1% of the current miles of Mains are of those smaller sizes.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Furthermore, of the current miles of mains, 70.1% of the Mains are plastic Material, 27.5% are Steel Mains and a minor 2.4% is of Cast Iron construction. Of the 27.5% of the total miles of Mains that are Steel Mains, 8.8% percent of the total miles Mains are Bare Steel and 18.7% are Coated Steel. Nearly all of the coated steel Mains are catholically protected either via the use of rectifiers or anode beds.

The Company's mains investment has continually grown over the years since the late 1920's through the present day. The growth occurred at a very rapid rate (double digit growth) during the 1950's and 1960's when natural gas was introduced, in lieu of manufactured gas plus dramatic economic growth was occurring, subsequent to which the growth level declined somewhat for a decade plus. However, starting during the early to mid 1980's through the mid 1990's, investment growth was extremely high ranging from ten (10) to more than thirty (30) percent per year. More recently, since the late 1990's the investment growth rate has moderated to the range of five (5) percent-plus or minus. The compound growth rate of the account investment over the history has aggregated in the range of approximately thirteen (13) percent. Along with the ongoing growth in additions, the level of property retirements have escalated in more recent years as various segments of the property continue to age. It is anticipated that sizable amounts of the increased retirements will occur within the Bare Steel Pipe category as well as the remaining limited Cast Iron Pipe. Other Mains categories can also be anticipated to experience increased retirements.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when a Main was being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 45-R3
Net Salv: -25%

Proposed Depreciation Parameters

ASL/Curve: 45-R3
Net Salv: -25%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.78 %	2.78 %
Av. Remaining Life	31.8 years	35.7 years
Reserve Amort. Amount	$16,179	$-59,571

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT - 376.30 Bare Steel Mains

Historical Experience

Plant Statistics	Plant Balance = $410,240 Average Age of Survivors = 45.7 years Original Gross Additions = $907,077 Oldest Surviving Vintage = 1928 Retirements = $496,836, or 54.8 % of historical additions. Average Age of Retirements = 40.2 years
Historical Retirement Rate Experience Bands	1991 – 2006 (Full Depth) 31-L3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-16%	-7%	-3%	-17%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -56%

Future Expectations and Considerations

The investment in gas mains is related to several types of pipe, as well as other appurtenant equipment. Accordingly, the investment in the account has been segmented into six (6) sub-account categories which include Cast Iron Mains, Joint Clamps, Steel Mains - Coated and Wrapped, Cathodic Protection, Steel Mains - Bare, and Plastic Mains. The various types of material components within the account represent the fact that the Company has generally installed different materials at various points throughout the history of the account. For example, Cast Iron Mains were principally installed beginning during the early 1900's (presently only a limited amount of Cast Iron remains in service); Bare Steel Mains were installed since the early 1900's through the early 1960's; Coated and Wrapped Steel Mains were installed from the early 1960's and continues through present day. During more recent times beginning with the early 1970's, through the present day, the Company has principally been installing a significant portion of its mains using plastic pipe. Also, beginning with the early 1970's and through recent years, the Company has been installing joint seals on its cast iron pipes to repair joint leaks and as well as to prevent joint leaks. Many of the earlier Joint Seals have since been retired along with the replaced Cast Iron pipe. In conjunction with its Coated and Wrapped Steel Mains, the Company has historical installed cathodic protection to prevent damages caused by corrosion.

As of December 31, 2006 the Company has approximately 465 miles of distribution main in service. Of the miles of Mains currently in service the majority of the Mains are of 4 Inch or smaller diameter. That is, more than 70.1% of the current miles of Mains are of those smaller sizes.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Furthermore, of the current miles of mains, 70.1% of the Mains are plastic Material, 27.5% are Steel Mains and a minor 2.4% is of Cast Iron construction. Of the 27.5% of the total miles of Mains that are Steel Mains, 8.8% percent of the total miles Mains are Bare Steel and 18.7% are Coated Steel. Nearly all of the coated steel Mains are catholically protected either via the use of rectifiers or anode beds.

The Company's mains investment has continually grown over the years since the late 1920's through the present day. The growth occurred at a very rapid rate (double digit growth) during the 1950's and 1960's when natural gas was introduced, in lieu of manufactured gas plus dramatic economic growth was occurring, subsequent to which the growth level declined somewhat for a decade plus. However, starting during the early to mid 1980's through the mid 1990's, investment growth was extremely high ranging from ten (10) to more than thirty (30) percent per year. More recently, since the late 1990's the investment growth rate has moderated to the range of five (5) percent-plus or minus. The compound growth rate of the account investment over the history has aggregated in the range of approximately thirteen (13) percent. Along with the ongoing growth in additions, the level of property retirements have escalated in more recent years as various segments of the property continue to age. It is anticipated that sizable amounts of the increased retirements will occur within the Bare Steel Pipe category as well as the remaining limited Cast Iron Pipe. Other Mains categories can also be anticipated to experience increased retirements.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when a Main was being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 31-L3
Net Salv: -25%

Proposed Depreciation Parameters

ASL/Curve: 31-L3
Net Salv: -25%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	4.03 %	4.03 %
Av. Remaining Life	6.5 years	6.9 years
Reserve Amort. Amount	$5,789	$-8,709

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.40 Plastic Mains

Historical Experience

Plant Statistics	Plant Balance = $37,913,691 Average Age of Survivors = 10.6 years Original Gross Additions = $38,552,405 Oldest Surviving Vintage = 1974 Retirements = $638,714, or 1.7 % of historical additions. Average Age of Retirements = 12.7 years
Historical Retirement Rate Experience Bands	1991 – 2006 (Full Depth) 35-R4

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-16%	-7%	-3%	-17%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -56%

Future Expectations and Considerations

The investment in gas mains is related to several types of pipe, as well as other appurtenant equipment. Accordingly, the investment in the account has been segmented into six (6) sub-account categories which include Cast Iron Mains, Joint Clamps, Steel Mains - Coated and Wrapped, Cathodic Protection, Steel Mains - Bare, and Plastic Mains. The various types of material components within the account represent the fact that the Company has generally installed different materials at various points throughout the history of the account. For example, Cast Iron Mains were principally installed beginning during the early 1900's (presently only a limited amount of Cast Iron remains in service); Bare Steel Mains were installed since the early 1900's through the early 1960's; Coated and Wrapped Steel Mains were installed from the early 1960's and continues through present day. During more recent times beginning with the early 1970's, through the present day, the Company has principally been installing a significant portion of its mains using plastic pipe. Also, beginning with the early 1970's and through recent years, the Company has been installing joint seals on its cast iron pipes to repair joint leaks and as well as to prevent joint leaks. Many of the earlier Joint Seals have since been retired along with the replaced Cast Iron pipe. In conjunction with its Coated and Wrapped Steel Mains, the Company has historical installed cathodic protection to prevent damages caused by corrosion.

As of December 31, 2006 the Company has approximately 465 miles of distribution main in service. Of the miles of Mains currently in service the majority of the Mains are of 4 Inch or smaller diameter. That is, more than 70.1% of the current miles of Mains are of those smaller sizes.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Furthermore, of the current miles of mains, 70.1% of the Mains are plastic Material, 27.5% are Steel Mains and a minor 2.4% is of Cast Iron construction. Of the 27.5% of the total miles of Mains that are Steel Mains, 8.8% percent of the total miles Mains are Bare Steel and 18.7% are Coated Steel. Nearly all of the coated steel Mains are catholically protected either via the use of rectifiers or anode beds.

The Company's mains investment has continually grown over the years since the late 1920's through the present day. The growth occurred at a very rapid rate (double digit growth) during the 1950's and 1960's when natural gas was introduced, in lieu of manufactured gas plus dramatic economic growth was occurring, subsequent to which the growth level declined somewhat for a decade plus. However, starting during the early to mid 1980's through the mid 1990's, investment growth was extremely high ranging from ten (10) to more than thirty (30) percent per year. More recently, since the late 1990's the investment growth rate has moderated to the range of five (5) percent-plus or minus. The compound growth rate of the account investment over the history has aggregated in the range of approximately thirteen (13) percent. Along with the ongoing growth in additions, the level of property retirements have escalated in more recent years as various segments of the property continue to age. It is anticipated that sizable amounts of the increased retirements will occur within the Bare Steel Pipe category as well as the remaining limited Cast Iron Pipe. Other Mains categories can also be anticipated to experience increased retirements.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when a Main was being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Specifically with regard to Plastic Mains and based upon discussions with Northern Utilities, Inc's- New Hampshire operations personnel it is noted that the Company has been using a medium density plastic pipe since the early 1980's that handles approximately 60 lbs of pressure. The earlier vintages of Plastic Mains have experienced replacement due to the replacement by a higher density plastic pipe that allows for 90 lbs of pipe pressure. The higher density of pipe began to be added to plant-in-service in 2000, and since 2005 the higher density pipe is the only plastic pipe that is used by the Company. Vintage 2001-2006 investments, which include the installation of increased amounts of higher density plastic pipe, comprises approximately 30% of the current Plastic Pipe investment.

The original life analysis for Plastic Pipe produced a life indication of "considerably less than 40 years", but based upon discussions with management, etc. a qualitative adjustment has been made to the proposed average service life for the property group.

Given the above referenced management input and related experience, it is noted that the lower density pipe has experienced and continues to face the potential of a far shorter life (especially in light of the current young age of the property). By comparison, it is anticipated that the higher density plastic pipe will likely experience a somewhat longer average service life. Therefore, weighting the 70% of the plastic pipe (medium density pipe) with a 40 year ASL together with 30% percent of the plastic pipe (higher density pipe) at 55 years (which is long based upon other depreciation study results) produces a composite 45 year life. Accordingly, a 45 year average service life is proposed for Plastic Mains at this time.

Life Analysis Method: Retirement Rate Method (Actuarial)

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 55-R2.5
Net Salv: -25%

Proposed Depreciation Parameters

ASL/Curve: Initial Life Indication of an Iowa 35-R4, but adjusted to an Iowa 45-S2
Net Salv: -25%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.78 %	2.27 %
Av. Remaining Life	34.7 years	42.7 years
Reserve Amort. Amount	$28,913	$-80,604

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.50 Joint Clamps

Historical Experience

Plant Statistics	Plant Balance = \$559,873
	Average Age of Survivors = 9.0 years
	Original Gross Additions = \$1,355,908
	Oldest Surviving Vintage = 1992
	Retirements = \$796,035, or 58.7 % of historical additions.
	Average Age of Retirements = 16.2 years

Historical
Retirement Rate
Experience Bands   1991 – 2006 (Full Depth) 15-S6

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-16%	-7%	-3%	-17%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -56%

Future Expectations and Considerations

The investment in gas mains is related to several types of pipe, as well as other appurtenant equipment. Accordingly, the investment in the account has been segmented into six (6) sub-account categories which include Cast Iron Mains, Joint Clamps, Steel Mains - Coated and Wrapped, Cathodic Protection, Steel Mains - Bare, and Plastic Mains. The various types of material components within the account represent the fact that the Company has generally installed different materials at various points throughout the history of the account. For example, Cast Iron Mains were principally installed beginning during the early 1900's (presently only a limited amount of Cast Iron remains in service); Bare Steel Mains were installed since the early 1900's through the early 1960's; Coated and Wrapped Steel Mains were installed from the early 1960's and continues through present day. During more recent times beginning with the early 1970's, through the present day, the Company has principally been installing a significant portion of its mains using plastic pipe. Also, beginning with the early 1970's and through recent years, the Company has been installing joint seals on its cast iron pipes to repair joint leaks and as well as to prevent joint leaks. Many of the earlier Joint Seals have since been retired along with the replaced Cast Iron pipe. In conjunction with its Coated and Wrapped Steel Mains, the Company has historical installed cathodic protection to prevent damages caused by corrosion.

As of December 31, 2006 the Company has approximately 465 miles of distribution main in service. Of the miles of Mains currently in service the majority of the Mains are of 4 Inch or smaller diameter. That is, more than 70.1% of the current miles of Mains are of those smaller sizes.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Furthermore, of the current miles of mains, 70.1% of the Mains are plastic Material, 27.5% are Steel Mains and a minor 2.4% is of Cast Iron construction. Of the 27.5% of the total miles of Mains that are Steel Mains, 8.8% percent of the total miles Mains are Bare Steel and 18.7% are Coated Steel. Nearly all of the coated steel Mains are catholically protected either via the use of rectifiers or anode beds.

The Company's mains investment has continually grown over the years since the late 1920's through the present day. The growth occurred at a very rapid rate (double digit growth) during the 1950's and 1960's when natural gas was introduced, in lieu of manufactured gas plus dramatic economic growth was occurring, subsequent to which the growth level declined somewhat for a decade plus. However, starting during the early to mid 1980's through the mid 1990's, investment growth was extremely high ranging from ten (10) to more than thirty (30) percent per year. More recently, since the late 1990's the investment growth rate has moderated to the range of five (5) percent-plus or minus. The compound growth rate of the account investment over the history has aggregated in the range of approximately thirteen (13) percent. Along with the ongoing growth in additions, the level of property retirements have escalated in more recent years as various segments of the property continue to age. It is anticipated that sizable amounts of the increased retirements will occur within the Bare Steel Pipe category as well as the remaining limited Cast Iron Pipe. Other Mains categories can also be anticipated to experience increased retirements.

As previously indicated, the Company has been installing joint clamps on its Cast Iron Mains in recent years to repair the joints where leaks occur. Furthermore, while the investments relative to Joint Clamps have historically been experiencing an average service life of fifteen (15) years, the useful average remaining life of the Joint Clamps will also be equal to or less than the remaining life of Cast Iron on which the Joint Clamp is installed. The application of the current estimated average service life parameters (Iowa 15-S6) to the present surviving vintage investment produces an average remaining life of 6.0 years, which is within a general range of the average remaining life of Cast Iron Mains.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when a Main was being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 15-S6
Net Salv: -25%

Proposed Depreciation Parameters

ASL/Curve: 15-S6
Net Salv: -25%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	8.33 %	8.33 %
Av. Remaining Life	6.1 years	5.9 years
Reserve Amort. Amount	$48,990	$-279

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.60 Cathodic Protection

Historical Experience

Plant Statistics	Plant Balance = $308,768 Average Age of Survivors = 7.2 years Original Gross Additions = $394,197 Oldest Surviving Vintage = 1991 Retirements = $85,429 or 21.7 % of historical additions. Average Age of Retirements = 18.4 years
Historical Retirement Rate Experience Bands	1991 – 2006 (Full Depth) 18-R5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-16%	-7%	-3%	-17%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -56%

Future Expectations and Considerations

The investment in gas mains is related to several types of pipe, as well as other appurtenant equipment. Accordingly, the investment in the account has been segmented into six (6) sub-account categories which include Cast Iron Mains, Joint Clamps, Steel Mains - Coated and Wrapped, Cathodic Protection, Steel Mains - Bare, and Plastic Mains. The various types of material components within the account represent the fact that the Company has generally installed different materials at various points throughout the history of the account. For example, Cast Iron Mains were principally installed beginning during the early 1900's (presently only a limited amount of Cast Iron remains in service); Bare Steel Mains were installed since the early 1900's through the early 1960's; Coated and Wrapped Steel Mains were installed from the early 1960's and continues through present day. During more recent times beginning with the early 1970's, through the present day, the Company has principally been installing a significant portion of its mains using plastic pipe. Also, beginning with the early 1970's and through recent years, the Company has been installing joint seals on its cast iron pipes to repair joint leaks and as well as to prevent joint leaks. Many of the earlier Joint Seals have since been retired along with the replaced Cast Iron pipe. In conjunction with its Coated and Wrapped Steel Mains, the Company has historical installed cathodic protection to prevent damages caused by corrosion.

As of December 31, 2006 the Company has approximately 465 miles of distribution main in service. Of the miles of Mains currently in service the majority of the Mains are of 4 Inch or smaller diameter. That is, more than 70.1% of the current miles of Mains are of those smaller sizes.

Furthermore, of the current miles of mains, 70.1% of the Mains are plastic Material, 27.5% are Steel Mains and a minor 2.4% is of Cast Iron construction. Of the 27.5% of the total miles of Mains that are Steel Mains, 8.8% percent of the total miles Mains are Bare Steel and 18.7% are Coated Steel. Nearly all of the coated steel Mains are catholically protected either via the use of rectifiers or anode beds.

The Company's mains investment has continually grown over the years since the late 1920's through the present day. The growth occurred at a very rapid rate (double digit growth) during the 1950's and 1960's when natural gas was introduced, in lieu of manufactured gas plus dramatic economic growth was occurring, subsequent to which the growth level declined somewhat for a decade plus. However, starting during the early to mid 1980's through the mid 1990's, investment growth was extremely high ranging from ten (10) to more than thirty (30) percent per year. More recently, since the late 1990's the investment growth rate has moderated to the range of five (5) percent-plus or minus. The compound growth rate of the account investment over the history has aggregated in the range of approximately thirteen (13) percent. Along with the ongoing growth in additions, the level of property retirements have escalated in more recent years as various segments of the property continue to age. It is anticipated that sizable amounts of the increased retirements will occur within the Bare Steel Pipe category as well as the remaining limited Cast Iron Pipe. Other Mains categories can also be anticipated to experience increased retirements.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when a Main was being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 18-R5
Net Salv: -25%

Proposed Depreciation Parameters

ASL/Curve: 18-R5
Net Salv: -25%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	6.94 %	6.94 %
Av. Remaining Life	10.8 years	13.6 years
Reserve Amort. Amount	$1,321	$-1,050

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.80 Cast Iron Mains

Historical Experience

Plant Statistics
Plant Balance = $87,713
Average Age of Survivors = 64.4 years
Original Gross Additions = $104,246
Oldest Surviving Vintage = 1939
Retirements = $52,532 or 50.4 % of historical additions.
Average Age of Retirements = 57.2 years

Historical Retirement Rate Experience Bands
1991 – 2006 (Full Depth) 62-S5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-16%	-7%	-3%	-17%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -56%

Future Expectations and Considerations

The investment in gas mains is related to several types of pipe, as well as other appurtenant equipment. Accordingly, the investment in the account has been segmented into six (6) sub-account categories which include Cast Iron Mains, Joint Clamps, Steel Mains - Coated and Wrapped, Cathodic Protection, Steel Mains - Bare, and Plastic Mains. The various types of material components within the account represent the fact that the Company has generally installed different materials at various points throughout the history of the account. For example, Cast Iron Mains were principally installed beginning during the early 1900's (presently only a limited amount of Cast Iron remains in service); Bare Steel Mains were installed since the early 1900's through the early 1960's; Coated and Wrapped Steel Mains were installed from the early 1960's and continues through present day. During more recent times beginning with the early 1970's, through the present day, the Company has principally been installing a significant portion of its mains using plastic pipe. Also, beginning with the early 1970's and through recent years, the Company has been installing joint seals on its cast iron pipes to repair joint leaks and as well as to prevent joint leaks. Many of the earlier Joint Seals have since been retired along with the replaced Cast Iron pipe. In conjunction with its Coated and Wrapped Steel Mains, the Company has historical installed cathodic protection to prevent damages caused by corrosion.

As of December 31, 2006 the Company has approximately 465 miles of distribution main in service. Of the miles of Mains currently in service the majority of the Mains are of 4 Inch or smaller diameter. That is, more than 70.1% of the current miles of Mains are of those smaller sizes.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Furthermore, of the current miles of mains, 70.1% of the Mains are plastic Material, 27.5% are Steel Mains and a minor 2.4% is of Cast Iron construction. Of the 27.5% of the total miles of Mains that are Steel Mains, 8.8% percent of the total miles Mains are Bare Steel and 18.7% are Coated Steel. Nearly all of the coated steel Mains are catholically protected either via the use of rectifiers or anode beds.

The Company's mains investment has continually grown over the years since the late 1920's through the present day. The growth occurred at a very rapid rate (double digit growth) during the 1950's and 1960's when natural gas was introduced, in lieu of manufactured gas plus dramatic economic growth was occurring, subsequent to which the growth level declined somewhat for a decade plus. However, starting during the early to mid 1980's through the mid 1990's, investment growth was extremely high ranging from ten (10) to more than thirty (30) percent per year. More recently, since the late 1990's the investment growth rate has moderated to the range of five (5) percent-plus or minus. The compound growth rate of the account investment over the history has aggregated in the range of approximately thirteen (13) percent. Along with the ongoing growth in additions, the level of property retirements have escalated in more recent years as various segments of the property continue to age. It is anticipated that sizable amounts of the increased retirements will occur within the Bare Steel Pipe category as well as the remaining limited Cast Iron Pipe. Other Mains categories can also be anticipated to experience increased retirements.

As previously indicated, the Company has been installing joint clamps on its Cast Iron Mains in recent years to repair the joints where leaks occur. Furthermore, while the investments relative to Joint Clamps have historically been experiencing an average service life of fifteen (15) years, the useful average remaining life of the Joint Clamps will also be equal to or less than the remaining life of Cast Iron on which the Joint Clamp is installed. The application of the current estimated average service life parameters (Iowa 15-S6) to the present surviving vintage investment produces an average remaining life of 6.0 years, which is within a general range of the average remaining life of Cast Iron Mains.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when a Main was being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 62-S5
Net Salv: -25%

Proposed Depreciation Parameters

ASL/Curve: 62-S%
Net Salv: -25%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.02 %	2.02 %
Av. Remaining Life	5.9 years	5.9 years
Reserve Amort. Amount	$1,557	$-2,107

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 378.20 Pumping & Regulating Equipment

Historical Experience

Plant Statistics	Plant Balance = $1,953,245
	Average Age of Survivors = 10.1 years
	Original Gross Additions = $2,067,236
	Oldest Surviving Vintage = 1956
	Retirements = $113,991, or 5.5 % of historical additions.
	Average Age of Retirements = 22.7 years

Historical
Retirement Rate
Experience Bands 1981 – 2006 (Full Depth) 30-R3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	2%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

The measuring and regulating equipment is utilized to regulate its gas pressure within its various service areas to the appropriate level to meet the customer needs. As the company continues to upgrade and/or modify its operating pressure within its service territory, ongoing changes will be required to the company's existing measuring and regulating facilities. Historically, the Company routinely upgraded two (2) to three (3) regulating stations per year of its approximately fifty (50) plus distribution stations. Many of the upgrades have been completed.

During prior years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when property was being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

It is anticipated that in the near future approximately twenty (20) regulating station currently owned and operated by a sister transmission company (Granite State Gas Transmission) will be sold to Northern Utilities-NH. It is expected that subsequent to the acquisition of the additional regulating stations increased amounts of rebuilds etc. may be required to integrate the facilities into the current operating system as well as to make the equipment more uniform and consistent with the Company's facilities for the purpose of uniform maintenance operations, etc.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 24-R3
Net Salv: -5%

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 30-R3
Net Salv: -5%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.50 %	4.38 %
Av. Remaining Life	20.6 years	18.7 years
Reserve Amort. Amount	$-9,839	$13,751

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 380.10 Bare Steel Services

Historical Experience

Plant Statistics	Plant Balance = $204,647
	Average Age of Survivors = 44.1 years
	Original Gross Additions = $321,023
	Oldest Surviving Vintage = 1934
	Retirements = $116,375, or 36.3 % of historical additions.
	Average Age of Retirements = 44.8 years

Historical
Retirement Rate
Experience Bands 1991 – 2005 (Full Depth) 47-R3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-134%	-143%	-115%	-90%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -169%

Future Expectations and Considerations

The Company's investment in services is comprised of several categories of material types, namely, Bare Steel Services; Coated and Not Wrapped Steel Services; Coated and Wrapped Steel Services; and Plastic Services. An analysis was performed using various Department of Transportation (DOT) reports, as well as other internal data sources, to identify the investment levels for each material type. The Company installed Bare Steel Services from the early 1900's through the 1960's, subsequent to which the Company then installed Coated and Not Wrapped Steel Services through the mid 1970's, and then some limited levels of Coated and Wrapped Steel Services during subsequent years to the present day. However, starting in the early 1970's, the Company began installing Plastic Services which has become nearly the exclusive component of the material utilized for customer services today.

As of December 31, 2006 the Company has 18,833 customer Services in service. Of the number of Services currently in service the over whelming majority of the Services are of 1 Inch or smaller diameter. That is, approximately 75% of the current number of Services are 1 Inch or smaller. Furthermore, of the current quantity of Services, 95% of the Services are plastic Material, with the remaining 5% being constructed of Steel material. Of the 5% of the total quantity of Services that are Steel Services, 3.1% percent of the total quantity of Services are Bare Steel and 2.0% are Coated Steel.

The Company's investment began to grow rapidly in the years since the early 1950's when natural gas became available in New England. Furthermore, as with the Company's Mains property category, the large majority of the account investment has been placed into service since the early 1980's and during the late 1990's, for which the Company's service investment growth has been in the range of five (5) to twenty-five (25) percent per year. During the property group's overall history, the investment in this account has experienced an average annual growth rate of more than thirteen (13) plus percent per year. Along with the increased growth in investment, the Company's replacement of existing facilities has continued to result in increased levels of retirements.

Similar to the Company's mains investment, it is anticipated that the Company will experience greater levels of property retirements relative to Bare Steel Services than experienced in earlier years due to increased age, as well as the Company's ongoing monitoring of the facilities.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when Services were being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 42-R2.5
Net Salv: -60%

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 47-R3
Net Salv: -85%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.94 %	3.82 %
Av. Remaining Life	11.1 years	11.7 years
Reserve Amort. Amount	$6,617	$9,761

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 380.20 Coated (Not Wrapped) Steel Services

Historical Experience

Plant Statistics	Plant Balance = $253,890
	Average Age of Survivors = 33.4 years
	Original Gross Additions = $377,489
	Oldest Surviving Vintage = 1968
	Retirements = $123,599, or 32.7 % of historical additions.
	Average Age of Retirements = 26.6 years

Historical
Retirement Rate
Experience Bands   1991 – 2006 (Full Depth) 38-L3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-134%	-143%	-115%	-90%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -169%

Future Expectations and Considerations

The Company's investment in services is comprised of several categories of material types, namely, Bare Steel Services; Coated and Not Wrapped Steel Services; Coated and Wrapped Steel Services; and Plastic Services. An analysis was performed using various Department of Transportation (DOT) reports, as well as other internal data sources, to identify the investment levels for each material type. The Company installed Bare Steel Services from the early 1900's through the 1960's, subsequent to which the Company then installed Coated and Not Wrapped Steel Services through the mid 1970's, and then some limited levels of Coated and Wrapped Steel Services during subsequent years to the present day. However, starting in the early 1970's, the Company began installing Plastic Services which has become nearly the exclusive component of the material utilized for customer services today.

As of December 31, 2006 the Company has 18,833 customer Services in service. Of the number of Services currently in service the over whelming majority of the Services are of 1 Inch or smaller diameter. That is, approximately 75% of the current number of Services are 1 Inch or smaller. Furthermore, of the current quantity of Services, 95% of the Services are plastic Material, with the remaining 5% being constructed of Steel material. Of the 5% of the total quantity of Services that are Steel Services, 3.1% percent of the total quantity of Services are Bare Steel and 2.0% are Coated Steel.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

The Company's investment began to grow rapidly in the years since the early 1950's when natural gas became available in New England. Furthermore, as with the Company's Mains property category, the large majority of the account investment has been placed into service since the early 1980's and during the late 1990's, for which the Company's service investment growth has been in the range of five (5) to twenty-five (25) percent per year. During the property group's overall history, the investment in this account has experienced an average annual growth rate of more than thirteen (13) plus percent per year. Along with the increased growth in investment, the Company's replacement of existing facilities has continued to result in increased levels of retirements.

Similar to the Company's mains investment, it is anticipated that the Company will experience greater levels of property retirements relative to Bare Steel Services than experienced in earlier years due to increased age, as well as the Company's ongoing monitoring of the facilities.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when Services were being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 42-R2.5
Net Salv: -60%

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 38-L3
Net Salv: -85%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	4.87 %	3.82 %
Av. Remaining Life	12.3 years	13.1 years
Reserve Amort. Amount	$6,541	$10,415

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 380.30 Coated & Wrapped Steel Services

Historical Experience

Plant Statistics	Plant Balance = $142,123 Average Age of Survivors = 26.7 years Original Gross Additions = $167,393 Oldest Surviving Vintage = 1977 Retirements = $25,269, or15.1 % of historical additions. Average Age of Retirements = 21.3 years
Historical Retirement Rate Experience Bands	1991 – 2006 (Full Depth) 38-R1.5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-134%	-143%	-115%	-90%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -169%

Future Expectations and Considerations

The Company's investment in services is comprised of several categories of material types, namely, Bare Steel Services; Coated and Not Wrapped Steel Services; Coated and Wrapped Steel Services; and Plastic Services. An analysis was performed using various Department of Transportation (DOT) reports, as well as other internal data sources, to identify the investment levels for each material type. The Company installed Bare Steel Services from the early 1900's through the 1960's, subsequent to which the Company then installed Coated and Not Wrapped Steel Services through the mid 1970's, and then some limited levels of Coated and Wrapped Steel Services during subsequent years to the present day. However, starting in the early 1970's, the Company began installing Plastic Services which has become nearly the exclusive component of the material utilized for customer services today.

As of December 31, 2006 the Company has 18,833 customer Services in service. Of the number of Services currently in service the over whelming majority of the Services are of 1 Inch or smaller diameter. That is, approximately 75% of the current number of Services are 1 Inch or smaller. Furthermore, of the current quantity of Services, 95% of the Services are plastic Material, with the remaining 5% being constructed of Steel material. Of the 5% of the total quantity of Services that are Steel Services, 3.1% percent of the total quantity of Services are Bare Steel and 2.0% are Coated Steel.

The Company's investment began to grow rapidly in the years since the early 1950's when natural gas became available in New England. Furthermore, as with the Company's Mains property category, the large majority of the account investment has been placed into service since the early 1980's and during the late 1990's, for which the Company's service investment growth has been in the range of five (5) to twenty-five (25) percent per year. During the property group's overall history, the investment in this account has experienced an average annual growth rate of more than thirteen (13) plus percent per year. Along with the increased growth in investment, the Company's replacement of existing facilities has continued to result in increased levels of retirements.

Similar to the Company's mains investment, it is anticipated that the Company will experience greater levels of property retirements relative to Bare Steel Services than experienced in earlier years due to increased age, as well as the Company's ongoing monitoring of the facilities.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when Services were being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 42-R2.5
Net Salv: -60%

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 38-R1.5
Net Salv: -85%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	4.87 %	3.82 %
Av. Remaining Life	18.3 years	22.3 years
Reserve Amort. Amount	$1,884	$3,705

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 380.40 Plastic Services

Historical Experience

Plant Statistics	Plant Balance = $23,317,517 Average Age of Survivors = 11.3 years Original Gross Additions = $23,934,793 Oldest Surviving Vintage = 1970 Retirements = $618,466, or 2.6 % of historical additions. Average Age of Retirements = 10.3 years
Historical Retirement Rate Experience Bands	1991 – 2006 (Full Depth) 40-R3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-134%	-143%	-115%	-90%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -169%

Future Expectations and Considerations

The Company's investment in services is comprised of several categories of material types, namely, Bare Steel Services; Coated and Not Wrapped Steel Services; Coated and Wrapped Steel Services; and Plastic Services. An analysis was performed using various Department of Transportation (DOT) reports, as well as other internal data sources, to identify the investment levels for each material type. The Company installed Bare Steel Services from the early 1900's through the 1960's, subsequent to which the Company then installed Coated and Not Wrapped Steel Services through the mid 1970's, and then some limited levels of Coated and Wrapped Steel Services during subsequent years to the present day. However, starting in the early 1970's, the Company began installing Plastic Services which has become nearly the exclusive component of the material utilized for customer services today.

As of December 31, 2006 the Company has 18,833 customer Services in service. Of the number of Services currently in service the over whelming majority of the Services are of 1 Inch or smaller diameter. That is, approximately 75% of the current number of Services are 1 Inch or smaller. Furthermore, of the current quantity of Services, 95% of the Services are plastic Material, with the remaining 5% being constructed of Steel material. Of the 5% of the total quantity of Services that are Steel Services, 3.1% percent of the total quantity of Services are Bare Steel and 2.0% are Coated Steel.

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

The Company's investment began to grow rapidly in the years since the early 1950's when natural gas became available in New England. Furthermore, as with the Company's Mains property category, the large majority of the account investment has been placed into service since the early 1980's and during the late 1990's, for which the Company's service investment growth has been in the range of five (5) to twenty-five (25) percent per year. During the property group's overall history, the investment in this account has experienced an average annual growth rate of more than thirteen (13) plus percent per year. Along with the increased growth in investment, the Company's replacement of existing facilities has continued to result in increased levels of retirements.

Similar to the Company's mains investment, it is anticipated that the Company will experience greater levels of property retirements relative to Bare Steel Services than experienced in earlier years due to increased age, as well as the Company's ongoing monitoring of the facilities.

During the last several years the charges for cost of removal have been inadvertently limited to the pure cost of abandonment when there is no replacement associated with it. In circumstances when Services were being replaced, the cost of removal has been inappropriately charged to the construction project to replace. Operating and corporate management is in the process of reviewing the recent practice and making the appropriate revisions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 42-R2.5
Net Salv: -60%

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 40-R3
Net Salv: -85%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	4.63 %	3.82 %
Av. Remaining Life	29.3 years	32.5 years
Reserve Amort. Amount	$99,234	$174,659

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 381.00 Customers' Meters

Historical Experience

Plant Statistics	Plant Balance = $2,432,023 Average Age of Survivors = 17.1 years Original Gross Additions = $2,634,497 Oldest Surviving Vintage = 1975 Retirements = $224,824 or 8.5 % of historical additions. Average Age of Retirements = 28.3 years
Historical Experience Bands	1980 – 2006 (Full Depth) 30-R5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	1%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -5%

Future Expectations and Considerations

The compound growth rate over the history of the account has been approximately thirteen (13) percent. The level of retirements relative to the current property in service has varied from year to year but on average has generally increased over time along with the increased level of investment. Most of the residential meters have previously been converted to ITRON meters. Conversely, a larger portion of the commercial customer meters remain to be converted to ITRON devices in coming years. A limited number of transportation meters are still served via Metscan, which is anticipated to continue for the foreseeable future.

While the company will continue to test and replace meters, as necessary, to meet regulatory requirements, continued implementation of technology changes may also be a driver for additional property changes. Also, the company has, in recent years, purchased new meters, as well as retrofit existing meters to read meter via computer control systems.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 30-R5
Net Salv: 0 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Proposed Depreciation Parameters

ASL/Curve: 30-R5
Net Salv: 0 %

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.33 %	3.33 %
Av. Remaining Life	13.5 years	16.2 years
Reserve Amort. Amount	$-2,092	$5,726

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 382.00 Meter Installations

Historical Experience

Plant Statistics

Plant Balance = $9,196,256
Average Age of Survivors = 9.0 years
Original Gross Additions = $9,511,018
Oldest Surviving Vintage = 1975
Retirements = $342,630 or 3.6 % of historical additions.
Average Age of Retirements = 29.3 years

Historical Experience Bands: 1980 – 2006 (Full Depth) 32-R4

Net Salvage: (01-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
-10%	-11%	-6%	-12%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -24%

Future Expectations and Considerations

The compound growth rate over the history of the account has been approximately fourteen (14) percent. The level of retirements relative to the current property in service has varied from year to year but on average has generally increased over time along with the increased level of investment. This account also includes the company's investment related to industrial meter's which are routinely larger investment and more subject to economic changes overtime.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 33-R4
Net Salv: -10 %

Proposed Depreciation Parameters

ASL/Curve: 32-R4
Net Salv: -10 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.44 %	3.33 %
Av. Remaining Life	23.2 years	26.1 years
Reserve Amort. Amount	$4,452	$10,869

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 383.00 Gas Regulators

Historical Experience

Plant Statistics	Plant Balance = $185,195 Average Age of Survivors = 5.0 years Original Gross Additions = $185,195 Oldest Surviving Vintage = 1999 Retirements = $0, or 0.0% of historical additions. Average Age of Retirements = 0.0 years
Historical Experience Bands	1980 – 2006 N/A Estimated 30-R3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1978-06
N/A	N/A	N/A	N/A

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
N/A	N/A	N/A	N/A

Forecasted Net Salvage: N/A

Future Expectations and Considerations

Gas regulators are required for all customers served within operating distribution systems operating above lower pressure level. Accordingly, the additions have been placed into service for this property class continuously over the life of the account with additions being related to additions of plant in conjunction with pressure rebuilds and new customers. To date no retirements have been recorded therefore no historical life analysis could be completed. It is recommended that the current underlying average service life parameters continue to be utilized.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 30-R3
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 30-R3
Net Salv: 0%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.33%	3.33%
Av. Remaining Life	25.2 years	28.9 years
Reserve Amort. Amount	$92	$79

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 386.1 & .2 Misc Property On Customers Premises (WH & CB)

Historical Experience

Plant Statistics
Plant Balance = $1,159,597
Average Age of Survivors = 7.0 years
Original Gross Additions = $4,140,308
Oldest Surviving Vintage = 1994
Retirements = $2,980,711 or 72.0 % of historical additions.
Average Age of Retirements = 10.6 years

Historical Experience Bands
1980 – 2006 (Full Depth) 10-R1.5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1988-06
1%	1%	1%	7%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
4%	1%	0%	1%

Forecasted Net Salvage: 1%

Future Expectations and Considerations

The investment in this account is related to the Company's investment in Water Heaters and Conversion Burner Units located at the customer's premise. Historical information indicates that the property and related investment within this property account is being replaced at increasing greater rates than in prior years.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: N/A
Net Salv: 0 %

Proposed Depreciation Parameters

ASL/Curve: 10-R1.5
Net Salv: 5 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	9.50 %	7.50 %
Av. Remaining Life	5.2 years	7.9 years
Reserve Amort. Amount	$-13,244	$22,684

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 391.10 Office Furniture & Equipment-Unspecified

Historical Experience

Plant Statistics
Plant Balance = $556,428
Average Age of Survivors = 10.2 years
Original Gross Additions = $1,181,375
Oldest Surviving Vintage = 1994
Retirements = $624,947 or 52.9 % of historical additions.
Average Age of Retirements = 9.3 years

Historical Experience Bands: 1991 – 2006 (Full Depth) 11-S3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	2%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
3%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

It is anticipated that this property class, which is impacted by the technological advances, routinely requires an ever greater frequency of upgrades and/or replacements.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 12-S5
Net Salv: 5 %

Proposed Depreciation Parameters

ASL/Curve: 11-S3
Net Salv: 2 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	8.91%	7.92%
Av. Remaining Life	2.8 years	8.2 years
Reserve Amort. Amount	$-34,845	$4,372

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 391.11 Office Furniture & Equipment-Data Handling Eq

Historical Experience

Plant Statistics	Plant Balance = $7,566 Average Age of Survivors = 2.5 years Original Gross Additions = $74,092 Oldest Surviving Vintage = 2004 Retirements = $66,527 or 89.8 % of historical additions. Average Age of Retirements = 10.7 years
Historical Experience Bands	1991 – 2006 (Full Depth) 10-R4

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	2%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
3%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

As with electronic-based office equipment, it is anticipated that this property class, which is impacted by the technological advances, routinely requires an ever greater frequency of upgrades and/or replacements.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: N/A
Net Salv: 0 %

Proposed Depreciation Parameters

ASL/Curve: 10-R4
Net Salv: 0 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	10.00 %	0.00 %
Av. Remaining Life	7.5 years	5.6 years
Reserve Amort. Amount	$251	$ 0

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 391.12 Information Systems

Historical Experience

Plant Statistics	Plant Balance = $123,870 Average Age of Survivors = 2.5 years Original Gross Additions = $1,373,033 Oldest Surviving Vintage = 2002 Retirements = $1,249,164 or 92.5 % of historical additions. Average Age of Retirements = 8.7 years
Historical Experience Bands	1991 – 2006 (Full Depth) 8-L4

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	2%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
3%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

As with electronic-based office equipment, it is anticipated that this property class, which is impacted by the technological advances, routinely requires an ever greater frequency of upgrades and/or replacements.

Life Analysis Method: Retirement Rate Method (Actuarial) – Life Span Method

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 8-L5
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 8-L4
Net Salv: 0%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	12.50 %	12.50 %
Av. Remaining Life	5.5 years	3.5 years
Reserve Amort. Amount	$-4,865	$8,651

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 392.00 Transportation Equipment

Historical Experience

Plant Statistics	Plant Balance = $38,676 Average Age of Survivors = 10.5 years Original Gross Additions = $790,394 Oldest Surviving Vintage = 1995 Retirements = $698,353 or 88.4 % of historical additions. Average Age of Retirements = 9.7 years
Historical Experience Bands	1981 – 2006 (Full Depth) 9-L4

Net Salvage: (81-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1981-06
0%	0%	0%	11%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
6%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

This account contains only a limited residual of owned equipment. Most of the equipment within this property class is being leased.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: N/A
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 9-L4
Net Salv: 10 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	0.00 %	0.00 %
Ave. Remaining Life	1.7 years	2.5 years
Reserve Amort. Amount	$ 0	$ 0

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 393.00 Stores Equipment

Historical Experience

Plant Statistics

Plant Balance = $31,520
Average Age of Survivors = 13.2 years
Original Gross Additions = $73,683
Oldest Surviving Vintage = 1992
Retirements = $60,360 or 82.0 % of historical additions.
Average Age of Retirements = 12.4 years

Historical Experience Bands: 1981 – 2006 (Full Depth) 13-L5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	0%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

The company's investment in this account is generally limited and is related to general storeroom equipment located at the company's various operations warehouses.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 12-S6
Net Salv: 0 %

Proposed Depreciation Parameters

ASL/Curve: 13-L5
Net Salv: 0 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	7.69%	8.33%
Av. Remaining Life	1.8 years	4.7 years
Reserve Amort. Amount	$-2,421	$-216

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 394.10 Tools, Garage & Service Equipment

Historical Experience

Plant Statistics	Plant Balance = $438,190 Average Age of Survivors = 11.5 years Original Gross Additions = $524,456 Oldest Surviving Vintage = 1986 Retirements = $86,267, or 16.4 % of historical additions. Average Age of Retirements = 15.8 years
Historical Experience Bands	1981 – 2006 (Full Depth) 19-R5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	0%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

The investment in this account is related to work tools used by the Company's work force to maintain the plant in service.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 17-S3
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 19-R5
Net Salv: 2%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	5.16 %	5.88 %
Av. Remaining Life	8. years	13.9 years
Reserve Amort. Amount	$-2,897	$-396

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 394.30 Tools, Tools & Other

Historical Experience

Plant Statistics

Plant Balance = $87,971
Average Age of Survivors = 5.6 years
Original Gross Additions = $95,232
Oldest Surviving Vintage = 1991
Retirements = $9,682, or 10.2 % of historical additions.
Average Age of Retirements = 15.9 years

Historical Experience Bands: 1966 – 2006 (Full Depth) 18-R5

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	0%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

The investment in this account is related to tools such as combustible gas indicator, CNG fuel maker, pipe locator, compactor, snow plow, etc. utilized by the company's employees in providing service to the company's customers.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 19-R3
Net Salv: 5 %

Proposed Depreciation Parameters

ASL/Curve: 18-R5
Net Salv: 2 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	5.44 %	5.00 %
Av. Remaining Life	12.4 years	13.9 years
Reserve Amort. Amount	$-1,122	$ 0

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 396.00 Power Operated Equipment

Historical Experience

Plant Statistics	Plant Balance = $75,266 Average Age of Survivors = 14.4 years Original Gross Additions = $270,224 Oldest Surviving Vintage = 1990 Retirements = $255,112, or 94.4 % of historical additions. Average Age of Retirements = 15.3 years
Historical Experience Bands	1982 – 2006 (Full Depth) 15-R4

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	14%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

This investment is related to equipment such as backhoe and compressor facilities utilized by the Company's work force.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 15-R3
Net Salv: 25 %

Proposed Depreciation Parameters

ASL/Curve: 15-R4
Net Salv: 10%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	6.00 %	5.00 %
Av. Remaining Life	3.0 years	N/A
Reserve Amort. Amount	$13,544	$-6,919

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 397.00 Communication Equipment

Historical Experience

Plant Statistics	Plant Balance = $321,226 Average Age of Survivors = 7.8 years Original Gross Additions = $913,945 Oldest Surviving Vintage = 1992 Retirements = $592,015, or 64.8 % of historical additions. Average Age of Retirements = 10.8 years
Historical Experience Bands	1984 – 2006 (Full Depth) 10-L3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	0%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

This investment is generally related to the company's phone system, radio detection equipment and telemetering receivers.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 12-R5
Net Salv: 0 %

Proposed Depreciation Parameters

ASL/Curve: 10-L3
Net Salv: 0 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	10.00 %	8.33 %
Av. Remaining Life	8.3 years	5.3 years
Reserve Amort. Amount	$-21,377	$-3,547

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 397.25 Communication Eq-Metscan Telemetering

Historical Experience

Plant Statistics	Plant Balance = $29,127 Average Age of Survivors = 1.7 years Original Gross Additions = $29,127 Oldest Surviving Vintage = 2004 Retirements = $0, or 0.0% of historical additions. Average Age of Retirements = 0.0 years
Historical Experience Bands	1991 – 2006 N/A Estimated 10-R3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	0%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

No retirements have occurred during the study period, therefore a life and curve is estimated for this investment based upon the typical content of the property group which includes Metscan communication equipment.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: N/A
Net Salv: 0 %

Proposed Depreciation Parameters

ASL/Curve: 10-R3
Net Salv: 0 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	10.00 %	8.33 %
Av. Remaining Life	8.4 years	N/A
Reserve Amort. Amount	$219	$ 0

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 397.35 Communication Eq-ITRON Equipment

Historical Experience

Plant Statistics
Plant Balance = $1,875,309
Average Age of Survivors = 3.3 years
Original Gross Additions = $1,875,309
Oldest Surviving Vintage = 2003
Retirements = $0, or 0.0% of historical additions.
Average Age of Retirements = 0.0 years

Historical Experience Bands: 1991 – 2006 N/A Estimated 10-R3

Net Salvage: (79-06)

Three Year Average Net Salvage Percent			Full Depth
2002-04	2003-05	2004-06	1979-06
0%	0%	0%	0%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Future Expectations and Considerations

No retirements have occurred during the study period, therefore a life and curve is estimated for this investment based upon the typical content of the property group, which includes ITRON communication equipment.

Life Analysis Method: Retirement Rate Method (Actuarial)

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: N/A
Net Salv: 0 %

Proposed Depreciation Parameters

ASL/Curve: 15-R3
Net Salv: 0 %

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

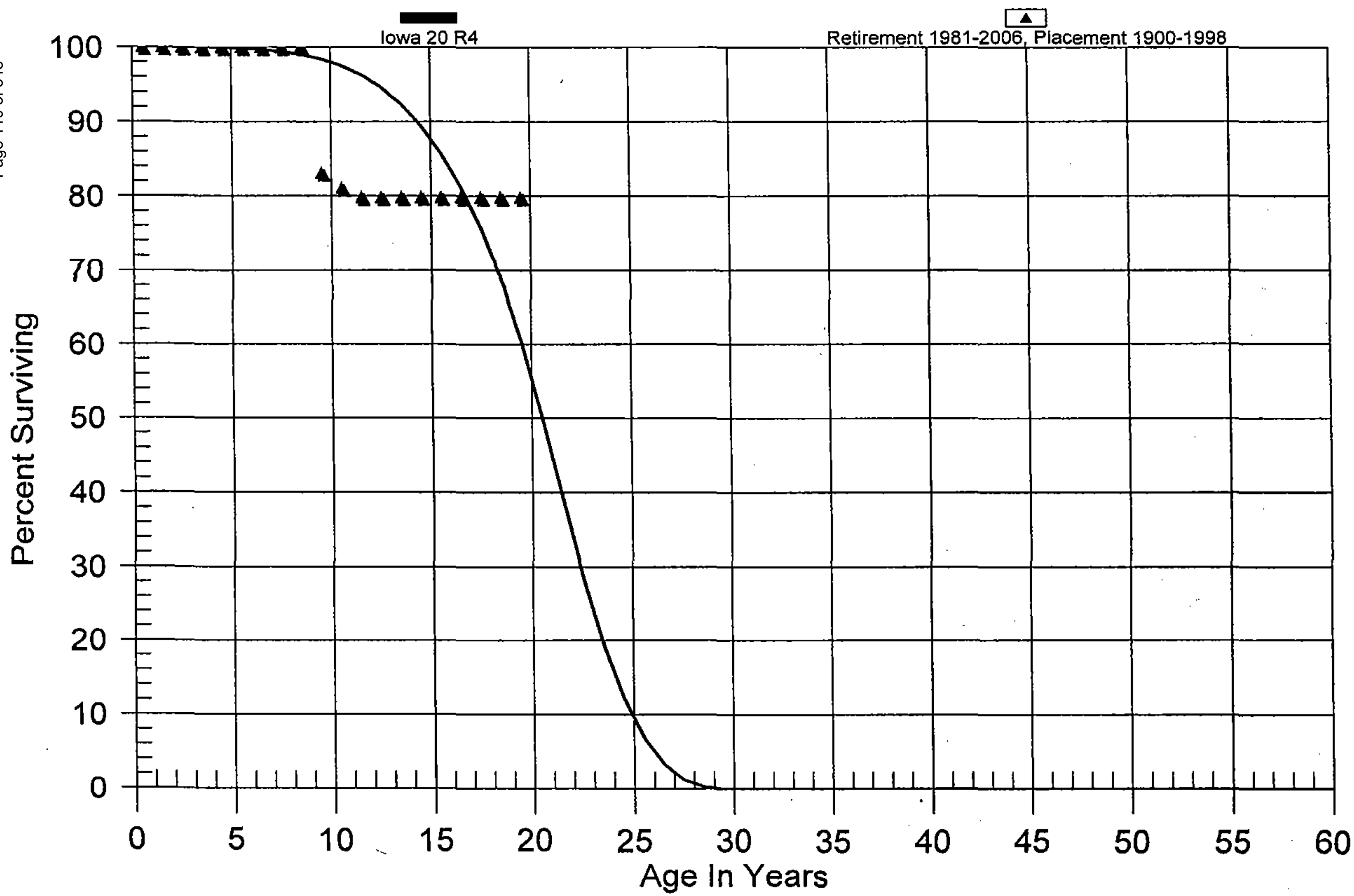
	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	6.67 %	7.14 %
Av. Remaining Life	11.7 years	4.9 years
Reserve Amort. Amount	$17,710	$ 0

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Section 5

Northern Utilities, Inc.

New Hampshire
320.00 OTHER PRODUCTION EQUIPMENT
Original And Smooth Survivor Curves



Northern Utilities, Inc.

New Hampshire

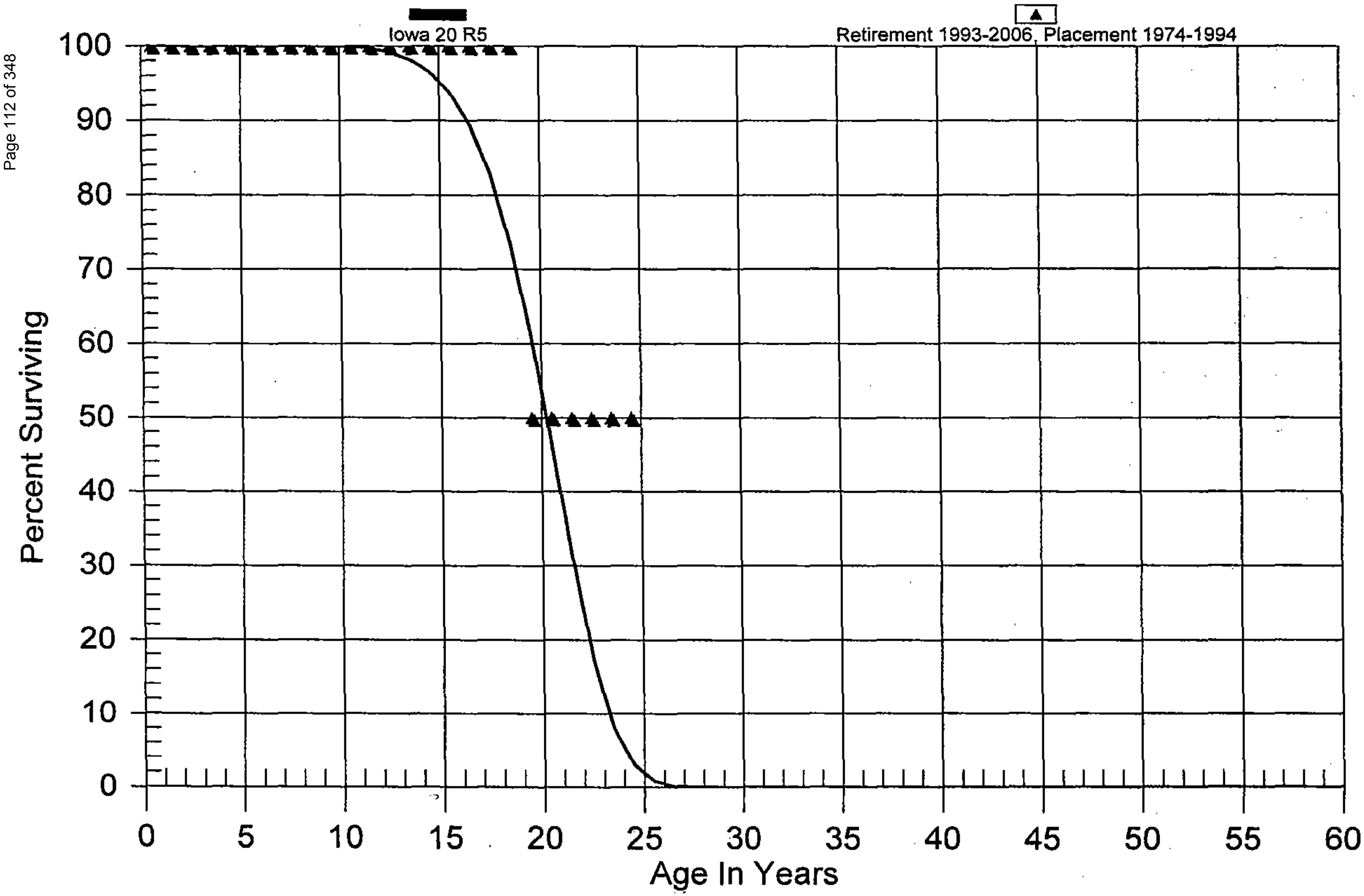
320.00 OTHER PRODUCTION EQUIPMENT

Observed Life Table

Retirement Expr. 1981 TO 2006
Placement Years 1900 TO 1998

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$26,723.41	$0.00	0.00000	100.00
0.5 - 1.5	$26,723.41	$0.00	0.00000	100.00
1.5 - 2.5	$26,723.41	$0.00	0.00000	100.00
2.5 - 3.5	$26,723.41	$0.00	0.00000	100.00
3.5 - 4.5	$26,723.41	$0.00	0.00000	100.00
4.5 - 5.5	$26,723.41	$0.00	0.00000	100.00
5.5 - 6.5	$26,723.41	$0.00	0.00000	100.00
6.5 - 7.5	$26,723.41	$0.00	0.00000	100.00
7.5 - 8.5	$26,723.41	$0.00	0.00000	100.00
8.5 - 9.5	$26,089.28	$4,400.00	0.16865	100.00
9.5 - 10.5	$24,089.28	$594.85	0.02469	83.13
10.5 - 11.5	$23,494.43	$350.00	0.01490	81.08
11.5 - 12.5	$23,144.43	$0.00	0.00000	79.87
12.5 - 13.5	$23,144.43	$0.00	0.00000	79.87
13.5 - 14.5	$16,728.40	$0.00	0.00000	79.87
14.5 - 15.5	$16,728.40	$0.00	0.00000	79.87
15.5 - 16.5	$16,728.40	$0.00	0.00000	79.87
16.5 - 17.5	$16,138.40	$0.00	0.00000	79.87
17.5 - 18.5	$16,138.40	$0.00	0.00000	79.87
18.5 - 19.5	$16,138.40	$0.00	0.00000	79.87

Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT
Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT

Observed Life Table
Retirement Expr. 1993 TO 2006
Placement Years 1974 TO 1994

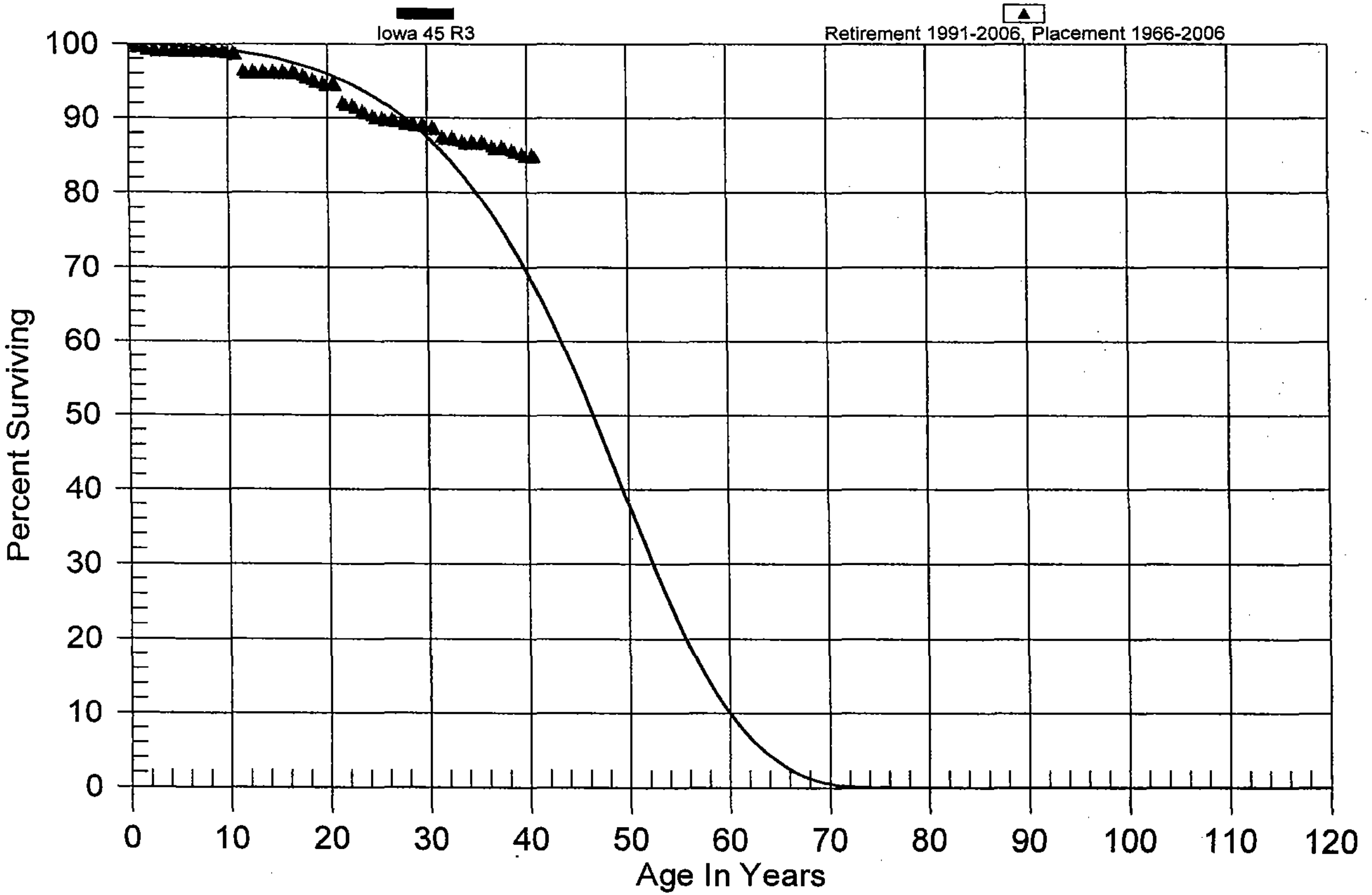
Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$37,263.93	$0.00	0.00000	100.00
0.5 - 1.5	$37,263.93	$0.00	0.00000	100.00
1.5 - 2.5	$37,263.93	$0.00	0.00000	100.00
2.5 - 3.5	$37,263.93	$0.00	0.00000	100.00
3.5 - 4.5	$37,263.93	$0.00	0.00000	100.00
4.5 - 5.5	$37,263.93	$0.00	0.00000	100.00
5.5 - 6.5	$37,263.93	$0.00	0.00000	100.00
6.5 - 7.5	$37,263.93	$0.00	0.00000	100.00
7.5 - 8.5	$37,263.93	$0.00	0.00000	100.00
8.5 - 9.5	$37,263.93	$0.00	0.00000	100.00
9.5 - 10.5	$37,263.93	$0.00	0.00000	100.00
10.5 - 11.5	$37,263.93	$0.00	0.00000	100.00
11.5 - 12.5	$37,263.93	$0.00	0.00000	100.00
12.5 - 13.5	$31,847.78	$0.00	0.00000	100.00
13.5 - 14.5	$0.00	$0.00	0.00000	100.00
14.5 - 15.5	$0.00	$0.00	0.00000	100.00
15.5 - 16.5	$0.00	$0.00	0.00000	100.00
16.5 - 17.5	$0.00	$0.00	0.00000	100.00
17.5 - 18.5	$0.00	$0.00	0.00000	100.00
18.5 - 19.5	$39,193.65	$19,596.82	0.50000	100.00
19.5 - 20.5	$19,596.83	$0.00	0.00000	50.00
20.5 - 21.5	$19,596.83	$0.00	0.00000	50.00
21.5 - 22.5	$19,596.83	$0.00	0.00000	50.00
22.5 - 23.5	$19,596.83	$0.00	0.00000	50.00
23.5 - 24.5	$19,596.83	$0.00	0.00000	50.00
24.5 - 25.5	$19,596.83	$0.00	0.00000	50.00
25.5 - 26.5	$19,596.83	$0.00	0.00000	50.00
26.5 - 27.5	$19,596.83	$0.00	0.00000	50.00
27.5 - 28.5	$19,596.83	$0.00	0.00000	50.00
28.5 - 29.5	$19,596.83	$0.00	0.00000	50.00
29.5 - 30.5	$19,596.83	$0.00	0.00000	50.00
30.5 - 31.5	$19,596.83	$0.00	0.00000	50.00
31.5 - 32.5	$19,596.83	$0.00	0.00000	50.00

Northern Utilities, Inc.

New Hampshire

376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)

Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)
Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1966 TO 2006

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$10,679,232.09	$98.00	0.00001	100.00
0.5 - 1.5	$11,084,572.62	$35,976.65	0.00325	100.00
1.5 - 2.5	$11,261,522.44	$26,976.34	0.00240	99.67
2.5 - 3.5	$11,297,101.61	$0.00	0.00000	99.44
3.5 - 4.5	$11,120,207.46	$0.00	0.00000	99.44
4.5 - 5.5	$10,612,635.29	$0.00	0.00000	99.44
5.5 - 6.5	$10,891,715.24	$3,944.72	0.00036	99.44
6.5 - 7.5	$10,724,506.35	$0.00	0.00000	99.40
7.5 - 8.5	$10,509,608.55	$0.00	0.00000	99.40
8.5 - 9.5	$10,449,738.87	$12,806.40	0.00123	99.40
9.5 - 10.5	$9,403,160.52	$26,721.09	0.00284	99.28
10.5 - 11.5	$6,658,964.58	$170,316.69	0.02558	99.00
11.5 - 12.5	$4,932,183.07	$0.00	0.00000	96.46
12.5 - 13.5	$5,024,401.37	$2.00	0.00000	96.46
13.5 - 14.5	$5,014,744.86	$665.00	0.00013	96.46
14.5 - 15.5	$4,931,055.91	$464.52	0.00009	96.45
15.5 - 16.5	$4,011,187.22	$589.76	0.00015	96.44
16.5 - 17.5	$3,254,003.70	$19,150.92	0.00589	96.43
17.5 - 18.5	$3,022,744.04	$18,736.54	0.00620	95.86
18.5 - 19.5	$2,929,016.99	$13,258.49	0.00453	95.27
19.5 - 20.5	$2,832,474.19	$20.20	0.00001	94.83
20.5 - 21.5	$2,685,275.90	$75,503.34	0.02812	94.83
21.5 - 22.5	$2,150,926.49	$9,062.79	0.00421	92.17
22.5 - 23.5	$1,973,184.58	$16,122.29	0.00817	91.78
23.5 - 24.5	$2,005,145.49	$13,268.26	0.00662	91.03
24.5 - 25.5	$1,968,184.87	$6,661.77	0.00338	90.43
25.5 - 26.5	$1,876,281.03	$4,232.23	0.00226	90.12
26.5 - 27.5	$1,817,004.75	$6,102.53	0.00336	89.92
27.5 - 28.5	$1,325,383.05	$3,488.18	0.00263	89.62
28.5 - 29.5	$1,151,801.31	$992.42	0.00086	89.38
29.5 - 30.5	$1,080,636.59	$4,832.35	0.00447	89.30
30.5 - 31.5	$965,059.98	$14,199.13	0.01471	88.90
31.5 - 32.5	$861,828.72	$842.67	0.00098	87.60
32.5 - 33.5	$747,222.27	$4,596.62	0.00615	87.51
33.5 - 34.5	$624,035.66	$0.00	0.00000	86.97
34.5 - 35.5	$533,048.68	$0.00	0.00000	86.97
35.5 - 36.5	$487,090.28	$3,778.87	0.00776	86.97

Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1966 TO 2006

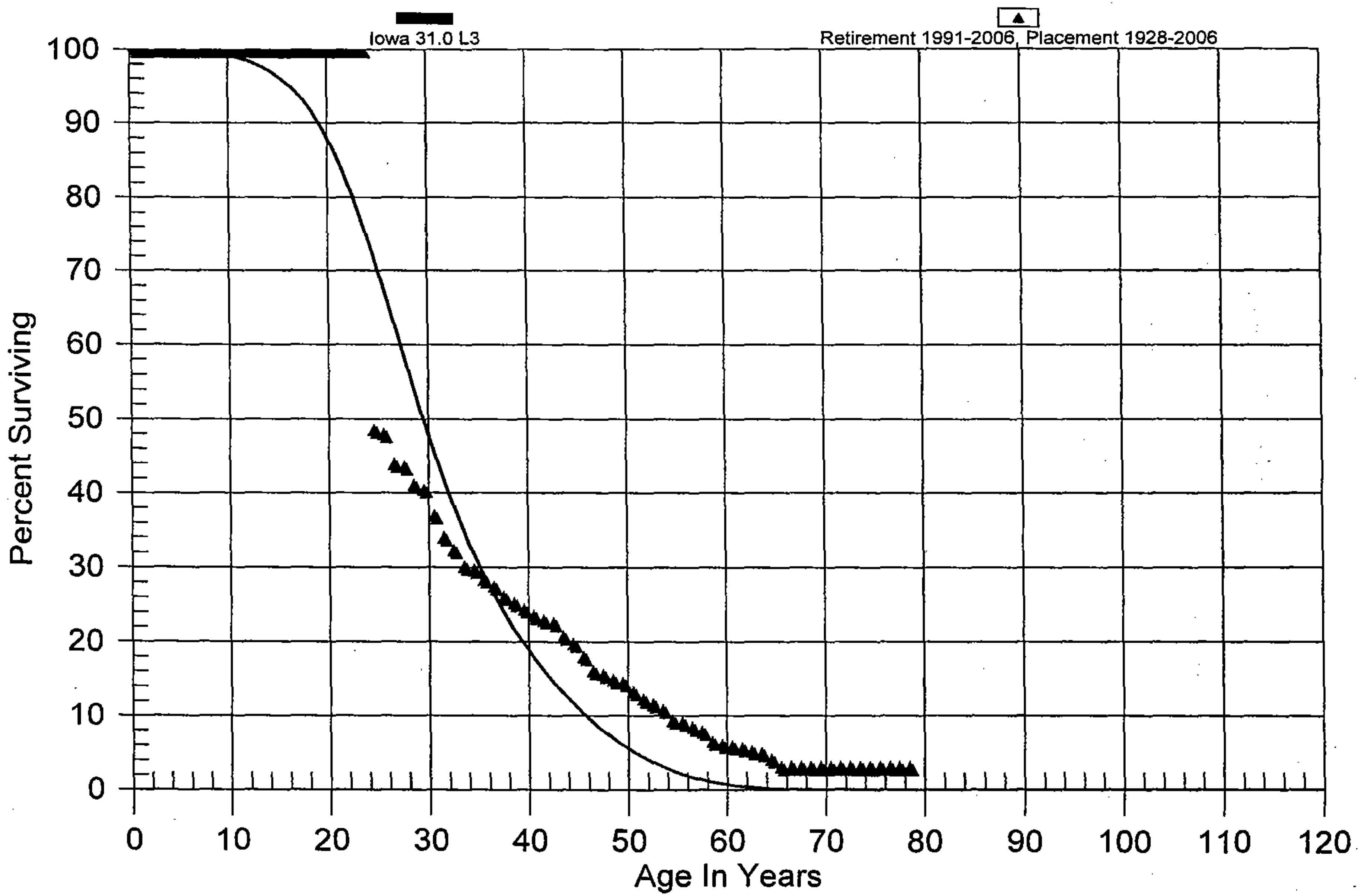
Age Interval	*\$ Surviving At Beginning of Age Interval*	*\$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
36.5 - 37.5	$370,386.67	$0.00	0.00000	86.30
37.5 - 38.5	$327,922.95	$1,876.42	0.00572	86.30
38.5 - 39.5	$243,283.62	$1,549.28	0.00637	85.80
39.5 - 40.5	$140,238.78	$146.10	0.00104	85.26

Northern Utilities, Inc.

New Hampshire

376.30 (367.60) MAINS - STEEL MAINS (BARE)

Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
376.30 (367.60) MAINS - STEEL MAINS (BARE)

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1928 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$10,464.49	$0.00	0.00000	100.00
0.5 - 1.5	$0.00	$0.00	0.00000	100.00
1.5 - 2.5	$0.00	$0.00	0.00000	100.00
2.5 - 3.5	$0.00	$0.00	0.00000	100.00
3.5 - 4.5	$0.00	$0.00	0.00000	100.00
4.5 - 5.5	$0.00	$0.00	0.00000	100.00
5.5 - 6.5	$0.00	$0.00	0.00000	100.00
6.5 - 7.5	$0.00	$0.00	0.00000	100.00
7.5 - 8.5	$0.00	$0.00	0.00000	100.00
8.5 - 9.5	$0.00	$0.00	0.00000	100.00
9.5 - 10.5	$0.00	$0.00	0.00000	100.00
10.5 - 11.5	$0.00	$0.00	0.00000	100.00
11.5 - 12.5	$0.00	$0.00	0.00000	100.00
12.5 - 13.5	$0.00	$0.00	0.00000	100.00
13.5 - 14.5	$0.00	$0.00	0.00000	100.00
14.5 - 15.5	$0.00	$0.00	0.00000	100.00
15.5 - 16.5	$0.00	$0.00	0.00000	100.00
16.5 - 17.5	$0.00	$0.00	0.00000	100.00
17.5 - 18.5	$0.00	$0.00	0.00000	100.00
18.5 - 19.5	$0.00	$0.00	0.00000	100.00
19.5 - 20.5	$0.00	$0.00	0.00000	100.00
20.5 - 21.5	$0.00	$0.00	0.00000	100.00
21.5 - 22.5	$0.00	$0.00	0.00000	100.00
22.5 - 23.5	$0.00	$0.00	0.00000	100.00
23.5 - 24.5	$18,543.37	$9,574.64	0.51634	100.00
24.5 - 25.5	$16,194.55	$182.64	0.01128	48.37
25.5 - 26.5	$71,192.02	$6,022.75	0.08460	47.82
26.5 - 27.5	$150,750.32	$1,164.39	0.00772	43.78
27.5 - 28.5	$309,205.91	$16,840.13	0.05446	43.44
28.5 - 29.5	$383,701.48	$6,041.06	0.01574	41.07
29.5 - 30.5	$456,962.86	$39,863.64	0.08724	40.42
30.5 - 31.5	$493,835.62	$40,376.95	0.08176	36.90
31.5 - 32.5	$475,087.40	$23,550.20	0.04957	33.88
32.5 - 33.5	$473,578.84	$30,721.63	0.06487	32.20
33.5 - 34.5	$463,529.29	$7,721.94	0.01666	30.11
34.5 - 35.5	$512,071.54	$22,256.52	0.04346	29.61
35.5 - 36.5	$531,181.79	$18,676.23	0.03516	28.32

Northern Utilities, Inc.
New Hampshire
376.30 (367.60) MAINS - STEEL MAINS (BARE)

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1928 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
36.5 - 37.5	$521,842.94	$24,858.97	0.04764	27.33
37.5 - 38.5	$506,790.19	$16,601.55	0.03276	26.03
38.5 - 39.5	$493,033.63	$17,694.37	0.03589	25.17
39.5 - 40.5	$476,042.26	$15,823.40	0.03324	24.27
40.5 - 41.5	$465,280.17	$11,984.03	0.02576	23.46
41.5 - 42.5	$443,678.42	$6,931.85	0.01562	22.86
42.5 - 43.5	$385,067.10	$31,552.61	0.08194	22.50
43.5 - 44.5	$247,841.97	$11,827.91	0.04772	20.66
44.5 - 45.5	$183,066.13	$16,219.33	0.08860	19.67
45.5 - 46.5	$161,138.02	$16,893.97	0.10484	17.93
46.5 - 47.5	$136,663.49	$4,500.24	0.03293	16.05
47.5 - 48.5	$118,107.15	$5,632.51	0.04769	15.52
48.5 - 49.5	$106,160.59	$2,804.12	0.02641	14.78
49.5 - 50.5	$155,813.26	$12,930.61	0.08299	14.39
50.5 - 51.5	$125,476.11	$9,426.84	0.07513	13.20
51.5 - 52.5	$106,776.48	$6,144.93	0.05755	12.20
52.5 - 53.5	$92,437.90	$6,239.59	0.06750	11.50
53.5 - 54.5	$79,285.89	$10,581.68	0.13346	10.73
54.5 - 55.5	$68,704.21	$1,658.04	0.02413	9.29
55.5 - 56.5	$67,046.17	$4,752.41	0.07088	9.07
56.5 - 57.5	$59,365.01	$4,294.97	0.07235	8.43
57.5 - 58.5	$54,673.85	$9,534.37	0.17439	7.82
58.5 - 59.5	$45,139.48	$2,615.88	0.05795	6.45
59.5 - 60.5	$42,523.60	$1,481.25	0.03483	6.08
60.5 - 61.5	$41,042.35	$2,084.81	0.05080	5.87
61.5 - 62.5	$37,092.90	$2,989.05	0.08058	5.57
62.5 - 63.5	$38,803.98	$1,832.54	0.04723	5.12
63.5 - 64.5	$36,971.44	$6,343.39	0.17158	4.88
64.5 - 65.5	$30,628.05	$7,608.44	0.24841	4.04
65.5 - 66.5	$12,437.63	$0.00	0.00000	3.04
66.5 - 67.5	$10,306.89	$0.00	0.00000	3.04
67.5 - 68.5	$4,700.13	$0.00	0.00000	3.04
68.5 - 69.5	$4,700.13	$0.00	0.00000	3.04
69.5 - 70.5	$4,700.13	$0.00	0.00000	3.04
70.5 - 71.5	$4,700.13	$0.00	0.00000	3.04
71.5 - 72.5	$4,700.13	$0.00	0.00000	3.04
72.5 - 73.5	$4,700.13	$0.00	0.00000	3.04

Northern Utilities, Inc.
New Hampshire
376.30 (367.60) MAINS - STEEL MAINS (BARE)

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1928 TO 2006

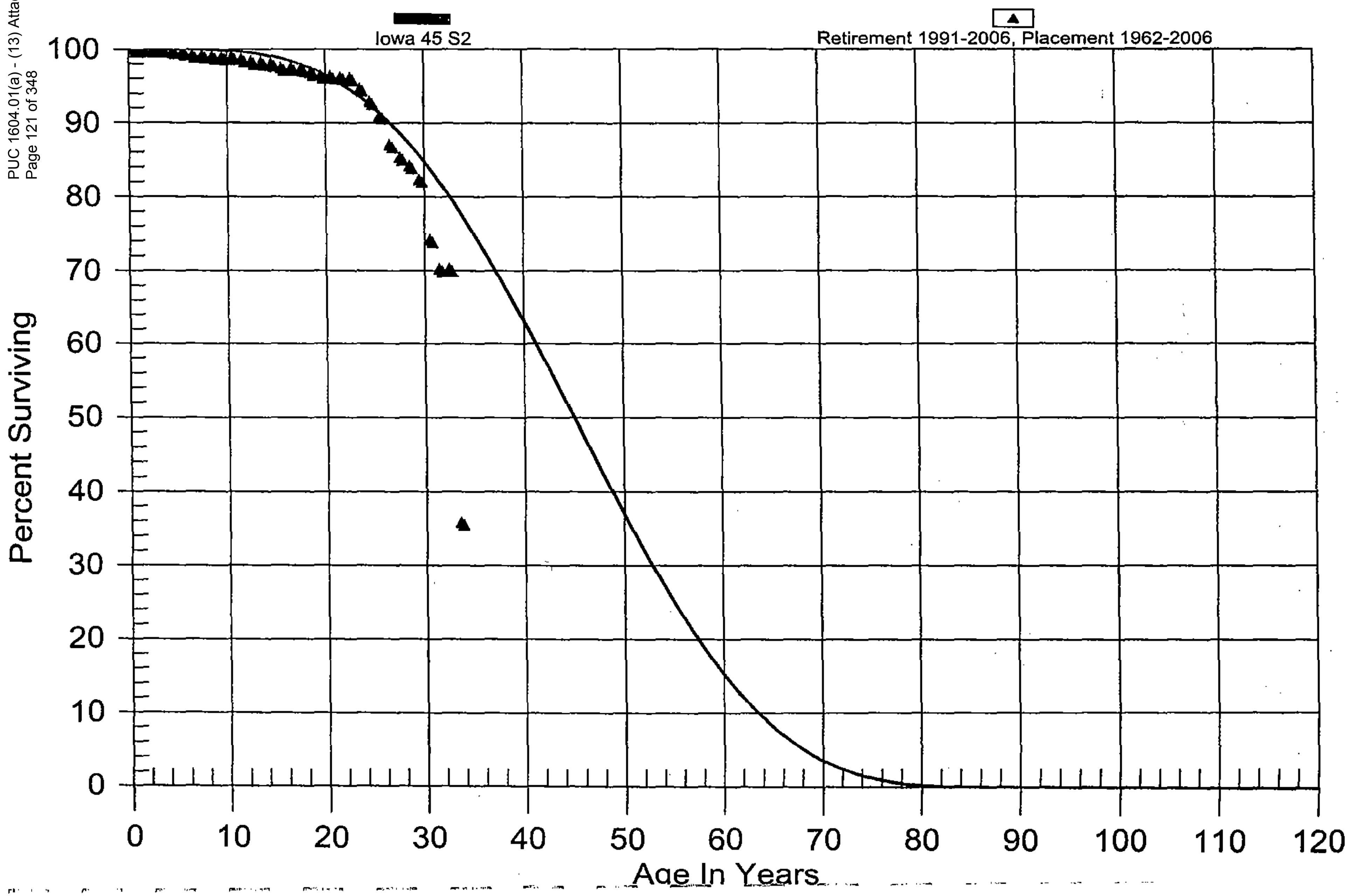
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
73.5 - 74.5	$4,700.13	$0.00	0.00000	3.04
74.5 - 75.5	$4,700.13	$0.00	0.00000	3.04
75.5 - 76.5	$4,700.13	$0.00	0.00000	3.04
76.5 - 77.5	$4,700.13	$0.00	0.00000	3.04
77.5 - 78.5	$4,700.13	$0.00	0.00000	3.04

Northern Utilities, Inc.

New Hampshire

376.40 (367.70) MAINS - PLASTIC

Original And Smooth Survivor Curves

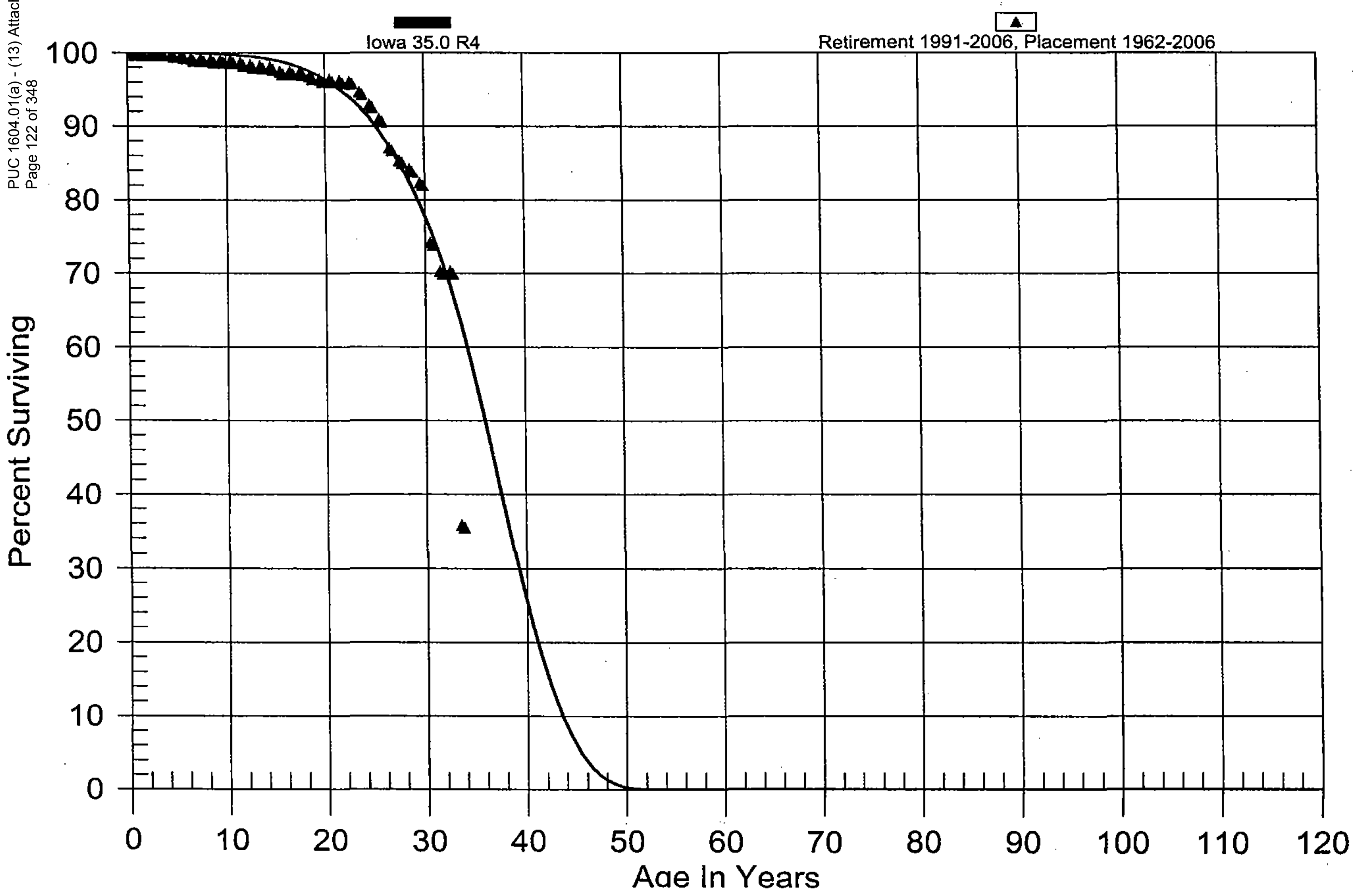


Northern Utilities, Inc.

New Hampshire

376.40 (367.70) MAINS - PLASTIC

Original And Smooth Survivor Curves



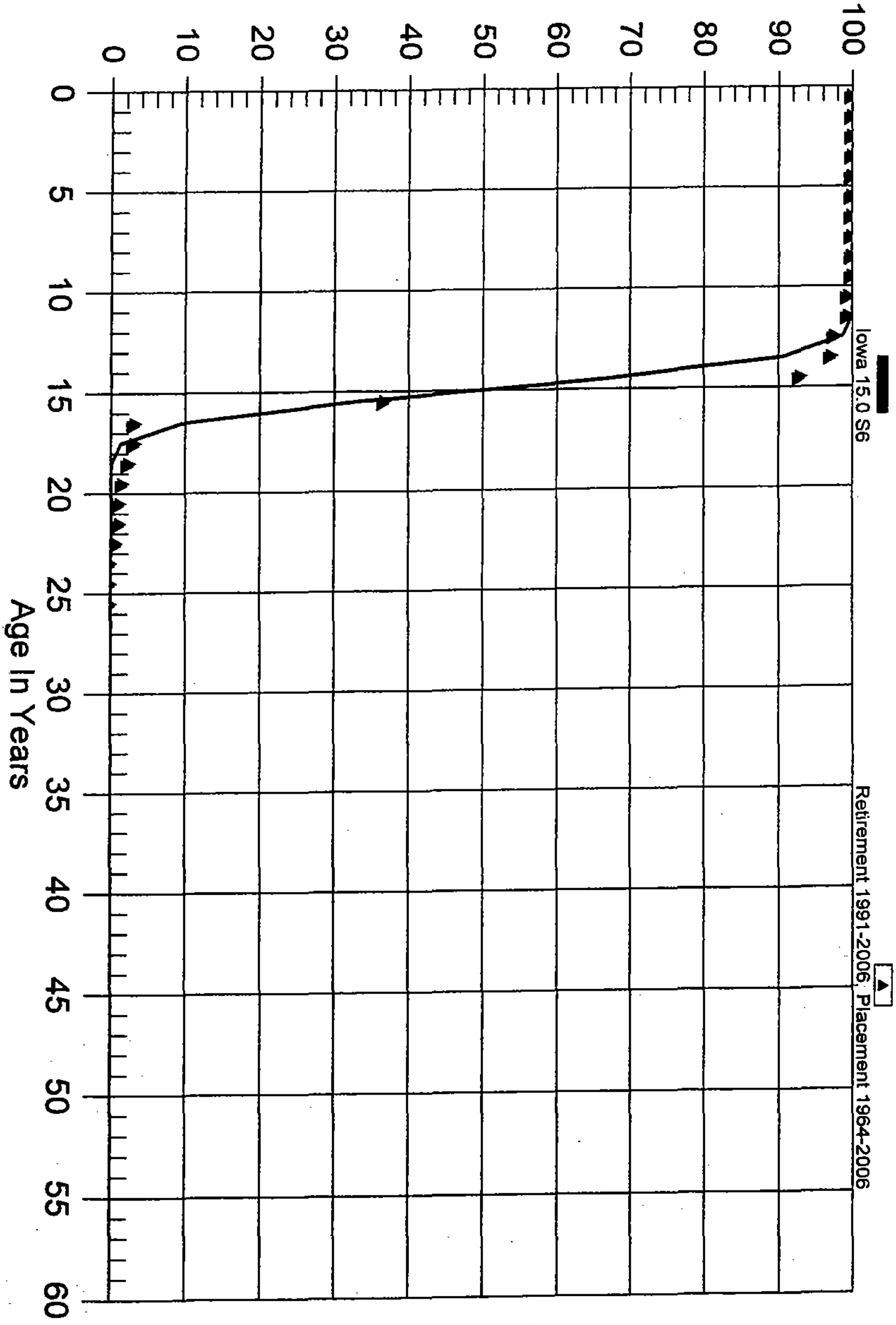
Northern Utilities, Inc.
New Hampshire
376.40 (367.70) MAINS - PLASTIC

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1962 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$30,473,088.22	$0.00	0.00000	100.00
0.5 - 1.5	$29,817,035.57	$12,231.65	0.00041	100.00
1.5 - 2.5	$28,408,391.56	$7,317.54	0.00026	99.96
2.5 - 3.5	$27,534,997.51	$4,318.25	0.00016	99.93
3.5 - 4.5	$27,458,781.12	$34,893.62	0.00127	99.92
4.5 - 5.5	$27,242,580.67	$45,613.91	0.00167	99.79
5.5 - 6.5	$26,209,584.71	$103,778.64	0.00396	99.62
6.5 - 7.5	$24,855,239.44	$5,124.76	0.00021	99.23
7.5 - 8.5	$22,993,589.23	$34,143.06	0.00148	99.21
8.5 - 9.5	$21,668,563.12	$14,642.80	0.00068	99.06
9.5 - 10.5	$20,350,321.38	$9,078.14	0.00045	98.99
10.5 - 11.5	$19,301,874.81	$63,586.13	0.00329	98.95
11.5 - 12.5	$17,734,314.02	$51,759.74	0.00292	98.62
12.5 - 13.5	$15,168,191.39	$15,767.62	0.00104	98.34
13.5 - 14.5	$13,465,248.83	$26,231.65	0.00195	98.23
14.5 - 15.5	$11,065,259.69	$63,659.56	0.00575	98.04
15.5 - 16.5	$7,891,329.93	$30.26	0.00000	97.48
16.5 - 17.5	$5,874,339.10	$5,311.86	0.00090	97.48
17.5 - 18.5	$4,785,158.93	$26,594.25	0.00556	97.39
18.5 - 19.5	$3,570,989.24	$15,440.51	0.00432	96.85
19.5 - 20.5	$2,406,865.72	$250.14	0.00010	96.43
20.5 - 21.5	$1,841,735.38	$3,059.94	0.00166	96.42
21.5 - 22.5	$1,284,850.80	$1,270.07	0.00099	96.26
22.5 - 23.5	$1,067,049.27	$16,534.94	0.01550	96.16
23.5 - 24.5	$906,698.34	$16,797.28	0.01853	94.67
24.5 - 25.5	$800,053.98	$16,597.20	0.02075	92.92
25.5 - 26.5	$529,415.01	$22,802.54	0.04307	90.99
26.5 - 27.5	$334,746.96	$6,585.47	0.01967	87.07
27.5 - 28.5	$178,607.23	$2,442.59	0.01368	85.36
28.5 - 29.5	$135,682.31	$2,980.06	0.02196	84.19
29.5 - 30.5	$78,175.73	$7,684.85	0.09830	82.34
30.5 - 31.5	$24,579.47	$1,295.53	0.05271	74.25
31.5 - 32.5	$2,980.29	$0.00	0.00000	70.34
32.5 - 33.5	$889.72	$436.96	0.49112	70.34

Northern Utilities, Inc.

New Hampshire
376.50 (367.20) MAINS - JOINT CLAMPS
Original And Smooth Survivor Curves
(Codes 0-7)



Northern Utilities, Inc.
New Hampshire
376.50 (367.20) MAINS - JOINT CLAMPS

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1964 TO 2006
(Codes 0-7)

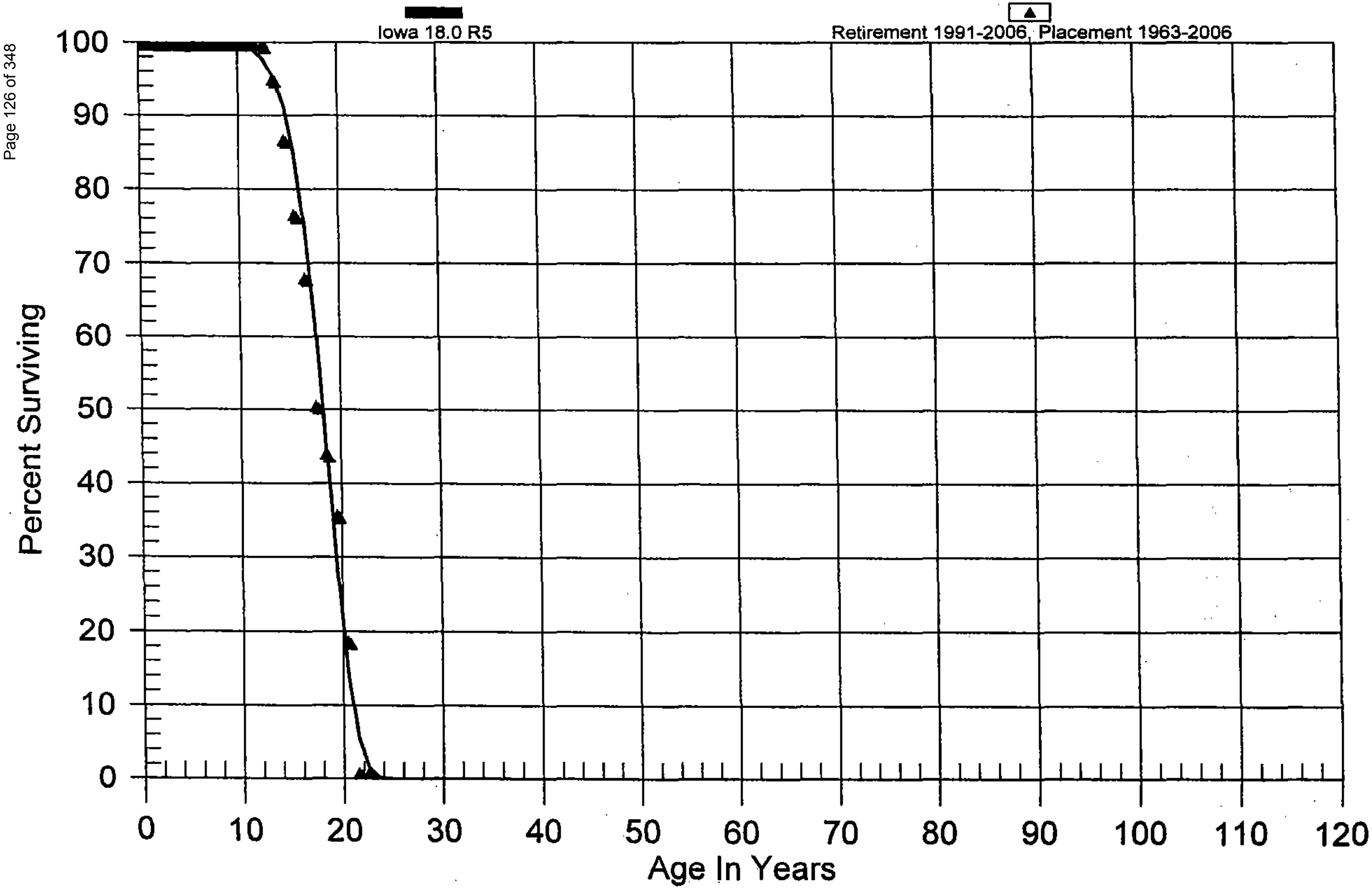
Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$696,273.89	$0.00	0.00000	100.00
0.5 - 1.5	$809,134.82	$0.00	0.00000	100.00
1.5 - 2.5	$838,938.48	$0.00	0.00000	100.00
2.5 - 3.5	$880,591.13	$0.00	0.00000	100.00
3.5 - 4.5	$941,864.22	$0.00	0.00000	100.00
4.5 - 5.5	$1,041,902.78	$0.00	0.00000	100.00
5.5 - 6.5	$1,074,638.25	$0.00	0.00000	100.00
6.5 - 7.5	$1,098,212.24	$0.00	0.00000	100.00
7.5 - 8.5	$1,119,560.47	$0.00	0.00000	100.00
8.5 - 9.5	$1,096,139.65	$0.00	0.00000	100.00
9.5 - 10.5	$1,008,118.88	$4,576.47	0.00454	100.00
10.5 - 11.5	$939,139.09	$0.00	0.00000	99.55
11.5 - 12.5	$910,515.51	$16,779.45	0.01843	99.55
12.5 - 13.5	$850,624.18	$4,550.71	0.00535	97.71
13.5 - 14.5	$764,713.93	$32,385.89	0.04235	97.19
14.5 - 15.5	$698,883.48	$422,621.28	0.60471	93.07
15.5 - 16.5	$277,882.32	$253,070.15	0.91071	36.79
16.5 - 17.5	$46,280.14	$0.00	0.00000	3.29
17.5 - 18.5	$52,891.53	$12,454.46	0.23547	3.29
18.5 - 19.5	$40,437.07	$12,598.30	0.31155	2.51
19.5 - 20.5	$27,838.77	$7,714.02	0.27710	1.73
20.5 - 21.5	$20,124.75	$0.00	0.00000	1.25
21.5 - 22.5	$20,637.14	$6,250.77	0.30289	1.25
22.5 - 23.5	$14,386.37	$13,873.98	0.96438	0.87
23.5 - 24.5	$512.39	$0.00	0.00000	0.03
24.5 - 25.5	$512.39	$0.00	0.00000	0.03

Northern Utilities, Inc.

New Hampshire

376.60 (367.50) MAINS - CATHODIC PROTECTION

Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
376.60 (367.50) MAINS - CATHODIC PROTECTION

Observed Life Table

Retirement Expr. 1991 TO 2006
Placement Years 1963 TO 2006

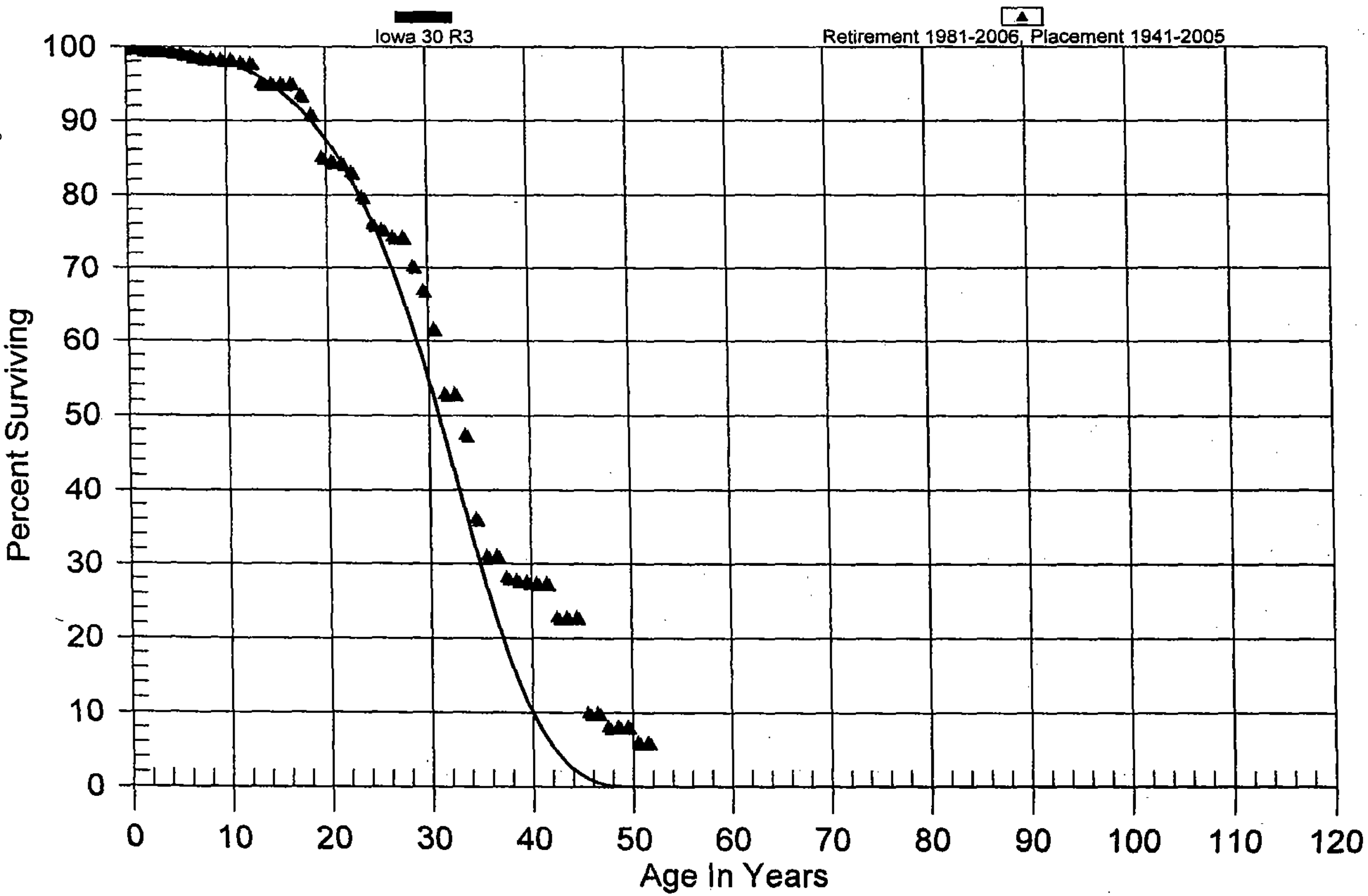
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$319,280.17	$0.00	0.00000	100.00
0.5 - 1.5	$294,333.88	$0.00	0.00000	100.00
1.5 - 2.5	$276,784.74	$0.00	0.00000	100.00
2.5 - 3.5	$245,040.00	$0.00	0.00000	100.00
3.5 - 4.5	$214,557.05	$0.00	0.00000	100.00
4.5 - 5.5	$207,100.51	$99.89	0.00048	100.00
5.5 - 6.5	$208,032.99	$0.00	0.00000	99.95
6.5 - 7.5	$208,932.89	$0.00	0.00000	99.95
7.5 - 8.5	$196,118.82	$0.00	0.00000	99.95
8.5 - 9.5	$139,995.05	$0.00	0.00000	99.95
9.5 - 10.5	$128,215.83	$0.00	0.00000	99.95
10.5 - 11.5	$131,419.14	$0.00	0.00000	99.95
11.5 - 12.5	$124,307.85	$414.41	0.00333	99.95
12.5 - 13.5	$111,838.44	$5,298.77	0.04738	99.62
13.5 - 14.5	$94,817.90	$8,222.80	0.08672	94.90
14.5 - 15.5	$69,535.74	$8,172.52	0.11753	86.67
15.5 - 16.5	$60,879.66	$6,794.56	0.11161	76.48
16.5 - 17.5	$54,085.10	$13,927.13	0.25750	67.95
17.5 - 18.5	$40,157.97	$5,174.59	0.12886	50.45
18.5 - 19.5	$34,983.38	$6,602.57	0.18873	43.95
19.5 - 20.5	$28,380.81	$13,512.64	0.47612	35.65
20.5 - 21.5	$14,868.17	$14,282.20	0.96059	18.68
21.5 - 22.5	$585.97	$0.00	0.00000	0.74

Northern Utilities, Inc.

New Hampshire

378.20 (369.00) PUMPING AND REG. STATION EQ.

Original And Smooth Survivor Curves



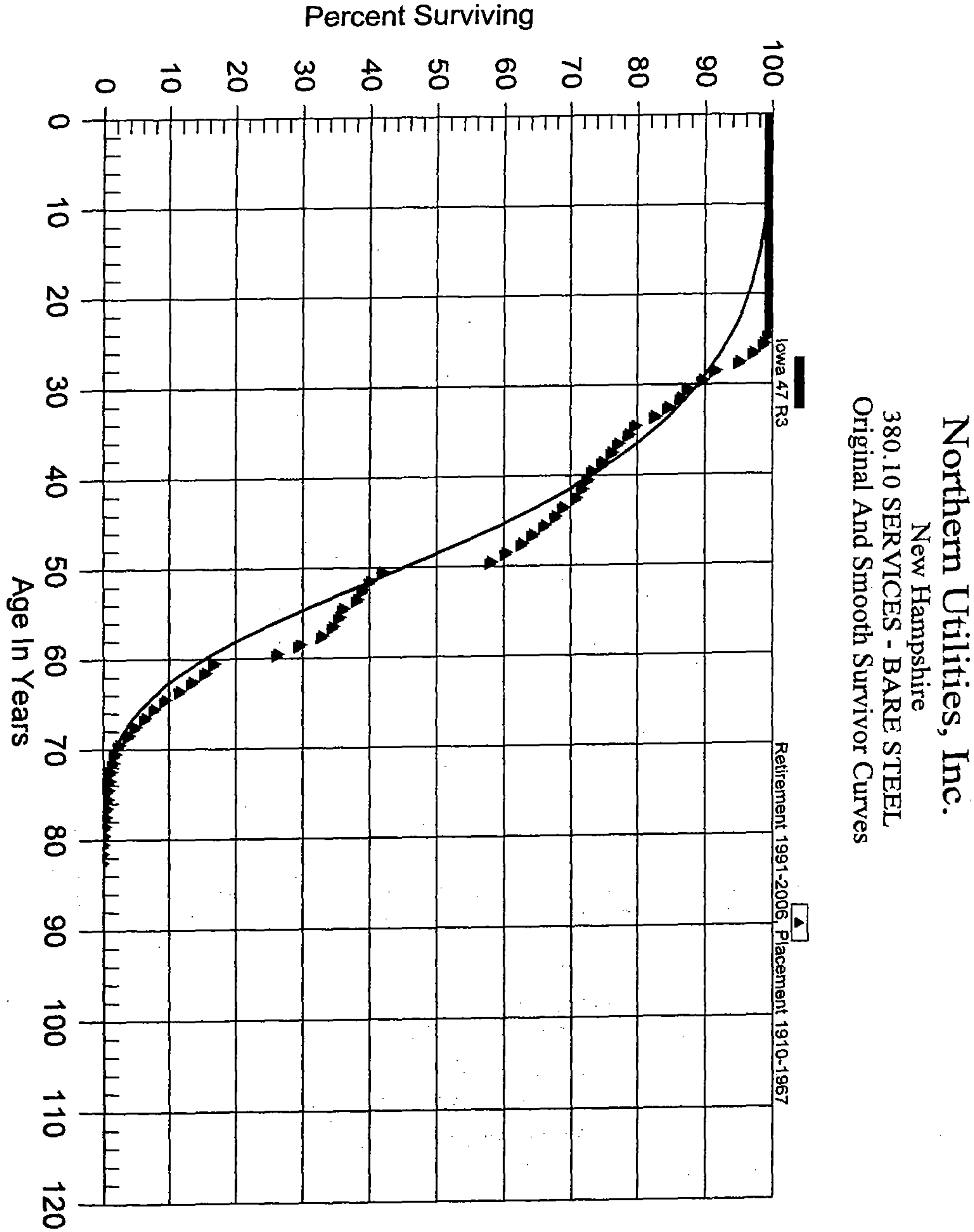
Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.
Observed Life Table
Retirement Expr. 1981 TO 2006
Placement Years 1941 TO 2005

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$1,913,926.57	$0.00	0.00000	100.00
0.5 - 1.5	$1,919,380.88	$4,472.79	0.00233	100.00
1.5 - 2.5	$1,850,218.39	$197.62	0.00011	99.77
2.5 - 3.5	$1,755,362.95	$0.00	0.00000	99.76
3.5 - 4.5	$1,664,571.62	$2,395.99	0.00144	99.76
4.5 - 5.5	$1,646,216.99	$5,328.40	0.00324	99.61
5.5 - 6.5	$1,590,285.60	$5,409.34	0.00340	99.29
6.5 - 7.5	$1,339,154.94	$3,421.12	0.00255	98.95
7.5 - 8.5	$1,168,368.74	$796.41	0.00068	98.70
8.5 - 9.5	$1,066,469.91	$2,192.45	0.00206	98.63
9.5 - 10.5	$918,109.65	$16.89	0.00002	98.43
10.5 - 11.5	$730,009.51	$2,533.65	0.00347	98.43
11.5 - 12.5	$612,236.90	$762.63	0.00125	98.09
12.5 - 13.5	$502,507.94	$14,122.39	0.02810	97.96
13.5 - 14.5	$441,226.59	$23.65	0.00005	95.21
14.5 - 15.5	$403,334.76	$0.00	0.00000	95.21
15.5 - 16.5	$304,630.32	$0.00	0.00000	95.21
16.5 - 17.5	$186,285.69	$3,058.31	0.01642	95.21
17.5 - 18.5	$156,356.50	$4,393.01	0.02810	93.64
18.5 - 19.5	$133,053.54	$8,453.42	0.06353	91.01
19.5 - 20.5	$126,218.34	$809.92	0.00642	85.23
20.5 - 21.5	$105,238.79	$362.96	0.00345	84.68
21.5 - 22.5	$87,320.95	$1,193.91	0.01367	84.39
22.5 - 23.5	$88,800.61	$3,519.35	0.03963	83.24
23.5 - 24.5	$90,319.97	$4,263.08	0.04720	79.94
24.5 - 25.5	$95,674.15	$851.82	0.00890	76.16
25.5 - 26.5	$93,166.42	$1,277.53	0.01371	75.49
26.5 - 27.5	$88,653.22	$0.00	0.00000	74.45
27.5 - 28.5	$64,061.21	$3,485.36	0.05441	74.45
28.5 - 29.5	$48,647.89	$2,308.98	0.04746	70.40
29.5 - 30.5	$46,477.28	$3,658.84	0.07872	67.06
30.5 - 31.5	$42,818.44	$6,076.61	0.14192	61.78
31.5 - 32.5	$36,741.83	$0.00	0.00000	53.01
32.5 - 33.5	$27,676.22	$2,837.57	0.10253	53.01
33.5 - 34.5	$21,869.56	$5,187.71	0.23721	47.58
34.5 - 35.5	$25,392.96	$3,517.88	0.13854	36.29
35.5 - 36.5	$20,785.44	$16.89	0.00081	31.26

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.

Observed Life Table
Retirement Expr. 1981 TO 2006
Placement Years 1941 TO 2005

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
36.5 - 37.5	$18,197.22	$1,675.97	0.09210	31.24
37.5 - 38.5	$16,521.25	$213.07	0.01290	28.36
38.5 - 39.5	$16,308.18	$124.62	0.00764	28.00
39.5 - 40.5	$18,742.19	$138.37	0.00738	27.78
40.5 - 41.5	$18,603.82	$0.00	0.00000	27.58
41.5 - 42.5	$18,603.82	$3,101.31	0.16670	27.58
42.5 - 43.5	$15,502.51	$0.00	0.00000	22.98
43.5 - 44.5	$15,502.51	$0.00	0.00000	22.98
44.5 - 45.5	$15,502.51	$8,711.11	0.56192	22.98
45.5 - 46.5	$6,791.40	$0.00	0.00000	10.07
46.5 - 47.5	$6,791.40	$1,234.70	0.18180	10.07
47.5 - 48.5	$5,556.70	$0.00	0.00000	8.24
48.5 - 49.5	$5,556.70	$0.00	0.00000	8.24
49.5 - 50.5	$5,556.70	$1,410.57	0.25385	8.24
50.5 - 51.5	$434.42	$0.00	0.00000	6.15


Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL
Original And Smooth Survivor Curves
Iowa 47 R3
Retirement 1991-2006, Placement 1910-1967
Percent Surviving
0
10
20
30
40
50
60
70
80
90
100
Age In Years
0
10
20
30
40
50
60
70
80
90
100
110
120

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1910 TO 1967

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$0.00	$0.00	0.00000	100.00
0.5 - 1.5	$0.00	$0.00	0.00000	100.00
1.5 - 2.5	$0.00	$0.00	0.00000	100.00
2.5 - 3.5	$0.00	$0.00	0.00000	100.00
3.5 - 4.5	$0.00	$0.00	0.00000	100.00
4.5 - 5.5	$0.00	$0.00	0.00000	100.00
5.5 - 6.5	$0.00	$0.00	0.00000	100.00
6.5 - 7.5	$0.00	$0.00	0.00000	100.00
7.5 - 8.5	$0.00	$0.00	0.00000	100.00
8.5 - 9.5	$0.00	$0.00	0.00000	100.00
9.5 - 10.5	$0.00	$0.00	0.00000	100.00
10.5 - 11.5	$0.00	$0.00	0.00000	100.00
11.5 - 12.5	$0.00	$0.00	0.00000	100.00
12.5 - 13.5	$0.00	$0.00	0.00000	100.00
13.5 - 14.5	$0.00	$0.00	0.00000	100.00
14.5 - 15.5	$0.00	$0.00	0.00000	100.00
15.5 - 16.5	$0.00	$0.00	0.00000	100.00
16.5 - 17.5	$0.00	$0.00	0.00000	100.00
17.5 - 18.5	$0.00	$0.00	0.00000	100.00
18.5 - 19.5	$0.00	$0.00	0.00000	100.00
19.5 - 20.5	$0.00	$0.00	0.00000	100.00
20.5 - 21.5	$0.00	$0.00	0.00000	100.00
21.5 - 22.5	$0.00	$0.00	0.00000	100.00
22.5 - 23.5	$0.00	$0.00	0.00000	100.00
23.5 - 24.5	$40,715.76	$117.58	0.00289	100.00
24.5 - 25.5	$69,069.11	$491.84	0.00712	99.71
25.5 - 26.5	$95,512.74	$1,588.56	0.01663	99.00
26.5 - 27.5	$127,748.91	$2,792.77	0.02186	97.35
27.5 - 28.5	$150,248.84	$5,435.37	0.03618	95.23
28.5 - 29.5	$172,095.54	$3,448.69	0.02004	91.78
29.5 - 30.5	$187,608.52	$4,613.64	0.02459	89.94
30.5 - 31.5	$197,447.02	$2,457.48	0.01245	87.73
31.5 - 32.5	$206,173.83	$4,161.32	0.02018	86.64
32.5 - 33.5	$213,488.37	$4,928.37	0.02308	84.89
33.5 - 34.5	$220,503.60	$7,899.61	0.03583	82.93
34.5 - 35.5	$223,715.38	$2,489.44	0.01113	79.96
35.5 - 36.5	$232,091.77	$4,673.57	0.02014	79.07

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Observed Life Table

Retirement Expr. 1991 TO 2006
Placement Years 1910 TO 1967

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
36.5 - 37.5	$235,052.28	$2,958.19	0.01259	77.48
37.5 - 38.5	$235,565.74	$4,328.88	0.01838	76.50
38.5 - 39.5	$232,452.30	$4,732.14	0.02036	75.10
39.5 - 40.5	$200,632.53	$1,886.63	0.00940	73.57
40.5 - 41.5	$178,765.45	$2,109.22	0.01180	72.88
41.5 - 42.5	$154,991.87	$1,998.29	0.01289	72.02
42.5 - 43.5	$125,043.14	$3,379.22	0.02702	71.09
43.5 - 44.5	$107,478.96	$1,771.75	0.01648	69.17
44.5 - 45.5	$83,680.29	$2,155.38	0.02576	68.03
45.5 - 46.5	$68,686.51	$1,769.68	0.02576	66.27
46.5 - 47.5	$61,199.78	$1,505.69	0.02460	64.57
47.5 - 48.5	$52,404.68	$1,984.52	0.03787	62.98
48.5 - 49.5	$43,680.33	$1,643.73	0.03763	60.59
49.5 - 50.5	$34,979.95	$9,629.57	0.27529	58.31
50.5 - 51.5	$23,822.44	$1,075.04	0.04513	42.26
51.5 - 52.5	$22,033.91	$652.59	0.02962	40.35
52.5 - 53.5	$20,886.36	$412.39	0.01974	39.16
53.5 - 54.5	$18,835.32	$1,013.78	0.05382	38.38
54.5 - 55.5	$17,803.27	$269.00	0.01511	36.32
55.5 - 56.5	$18,297.13	$486.95	0.02661	35.77
56.5 - 57.5	$18,774.46	$874.35	0.04657	34.82
57.5 - 58.5	$17,949.93	$1,795.48	0.10003	33.20
58.5 - 59.5	$15,569.79	$1,747.00	0.11220	29.88
59.5 - 60.5	$13,043.12	$4,683.82	0.35910	26.52
60.5 - 61.5	$8,674.45	$652.21	0.07519	17.00
61.5 - 62.5	$8,073.06	$980.63	0.12147	15.72
62.5 - 63.5	$7,383.29	$1,045.46	0.14160	13.81
63.5 - 64.5	$6,837.83	$1,297.60	0.18977	11.86
64.5 - 65.5	$6,040.23	$1,055.36	0.17472	9.61
65.5 - 66.5	$5,484.87	$925.17	0.16868	7.93
66.5 - 67.5	$5,037.38	$1,173.66	0.23299	6.59
67.5 - 68.5	$3,927.92	$763.94	0.19449	5.05
68.5 - 69.5	$3,547.73	$1,253.94	0.35345	4.07
69.5 - 70.5	$2,739.25	$572.76	0.20909	2.63
70.5 - 71.5	$2,666.49	$500.05	0.18753	2.08
71.5 - 72.5	$2,648.26	$490.91	0.18537	1.69
72.5 - 73.5	$2,574.64	$290.98	0.11302	1.38

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1910 TO 1967

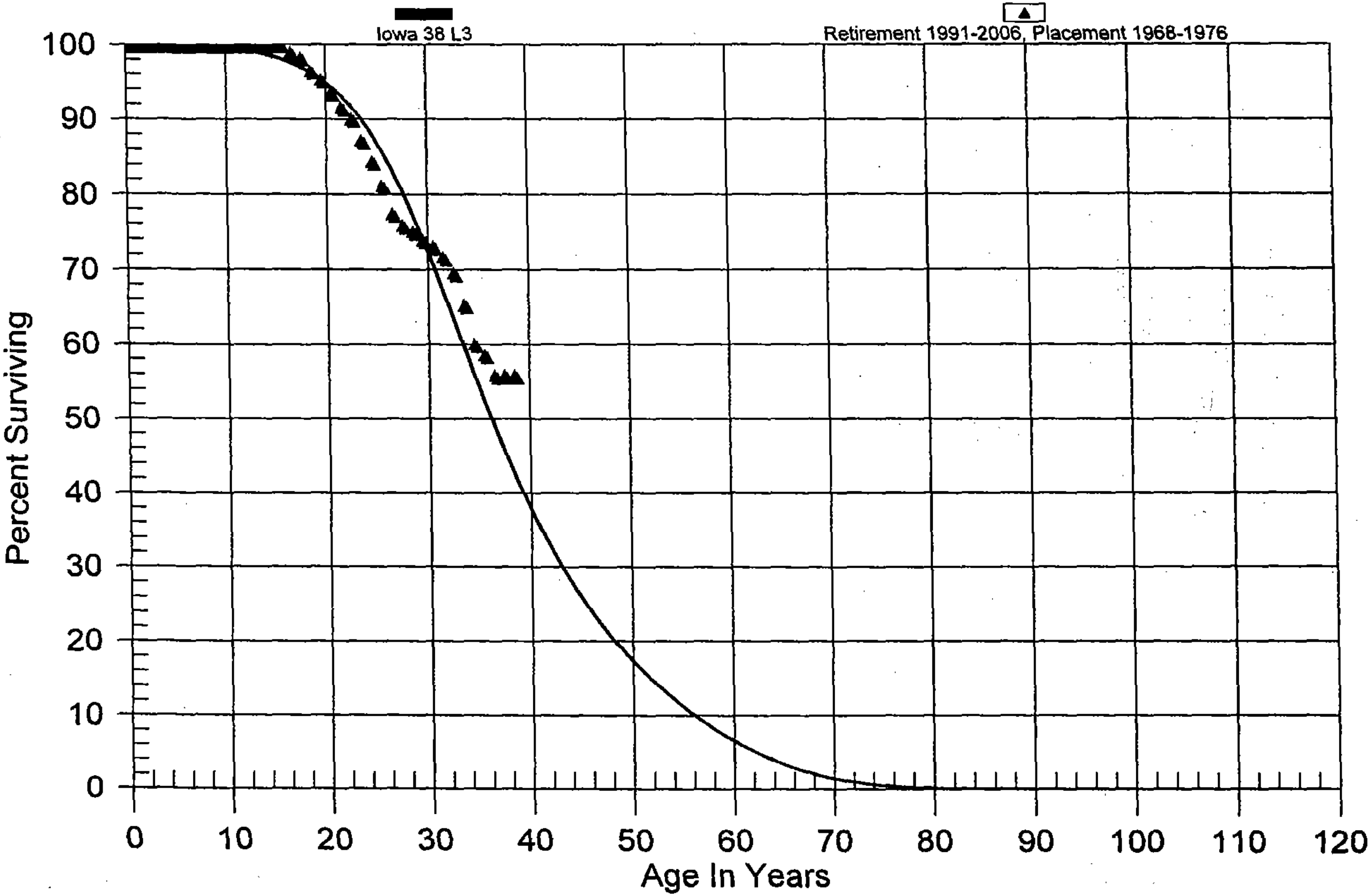
Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
73.5 - 74.5	$2,774.57	$383.65	0.13827	1.22
74.5 - 75.5	$2,890.92	$454.55	0.15723	1.05
75.5 - 76.5	$2,909.10	$536.36	0.18437	0.89
76.5 - 77.5	$2,863.65	$463.64	0.16191	0.72
77.5 - 78.5	$2,845.47	$536.36	0.18850	0.61
78.5 - 79.5	$2,809.11	$908.05	0.32325	0.49
79.5 - 80.5	$1,901.06	$666.71	0.35070	0.33
80.5 - 81.5	$1,461.63	$725.24	0.49619	0.22
81.5 - 82.5	$736.39	$572.74	0.77777	0.11

Northern Utilities, Inc.

New Hampshire

380.20 SERVICES - COATED STEEL NOT WRAPPED

Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
380.20 SERVICES - COATED STEEL NOT WRAPPED
Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1968 TO 1976

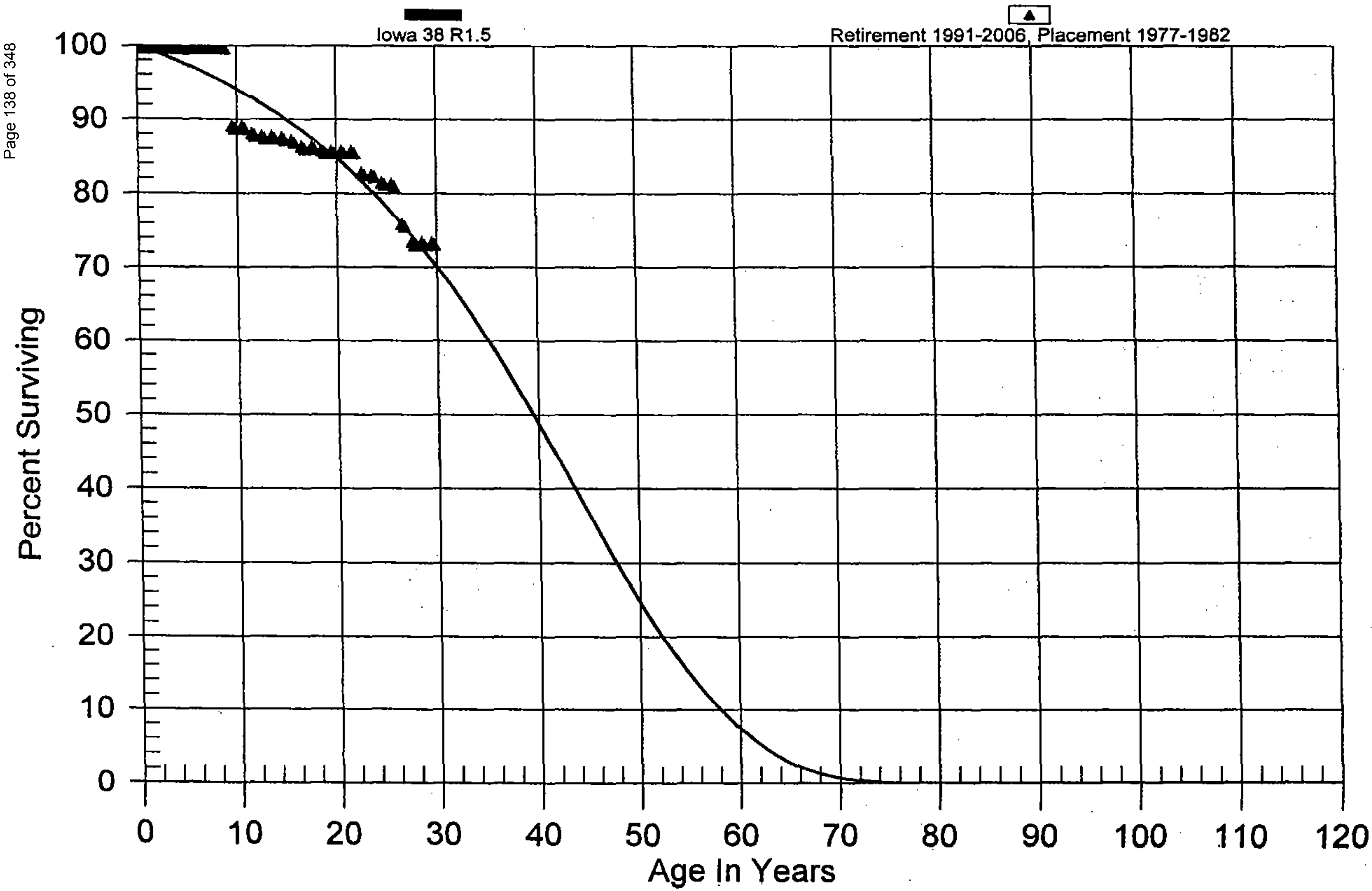
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$0.00	$0.00	0.00000	100.00
0.5 - 1.5	$0.00	$0.00	0.00000	100.00
1.5 - 2.5	$0.00	$0.00	0.00000	100.00
2.5 - 3.5	$0.00	$0.00	0.00000	100.00
3.5 - 4.5	$0.00	$0.00	0.00000	100.00
4.5 - 5.5	$0.00	$0.00	0.00000	100.00
5.5 - 6.5	$0.00	$0.00	0.00000	100.00
6.5 - 7.5	$0.00	$0.00	0.00000	100.00
7.5 - 8.5	$0.00	$0.00	0.00000	100.00
8.5 - 9.5	$0.00	$0.00	0.00000	100.00
9.5 - 10.5	$0.00	$0.00	0.00000	100.00
10.5 - 11.5	$0.00	$0.00	0.00000	100.00
11.5 - 12.5	$0.00	$0.00	0.00000	100.00
12.5 - 13.5	$0.00	$0.00	0.00000	100.00
13.5 - 14.5	$0.00	$0.00	0.00000	100.00
14.5 - 15.5	$53,786.39	$0.00	0.00000	100.00
15.5 - 16.5	$102,920.66	$1,097.51	0.01066	100.00
16.5 - 17.5	$175,780.10	$1,239.59	0.00705	98.93
17.5 - 18.5	$222,372.22	$4,162.91	0.01872	98.24
18.5 - 19.5	$262,452.11	$3,288.47	0.01253	96.40
19.5 - 20.5	$297,060.28	$5,242.10	0.01765	95.19
20.5 - 21.5	$319,080.55	$6,847.55	0.02146	93.51
21.5 - 22.5	$324,924.95	$5,320.97	0.01638	91.50
22.5 - 23.5	$350,290.11	$11,220.83	0.03203	90.00
23.5 - 24.5	$339,069.28	$10,800.42	0.03185	87.12
24.5 - 25.5	$328,268.86	$12,590.95	0.03836	84.35
25.5 - 26.5	$315,677.91	$14,638.19	0.04637	81.11
26.5 - 27.5	$301,039.72	$5,994.60	0.01991	77.35
27.5 - 28.5	$295,045.12	$3,077.28	0.01043	75.81
28.5 - 29.5	$291,967.84	$4,354.23	0.01491	75.02
29.5 - 30.5	$287,613.61	$3,481.21	0.01210	73.90
30.5 - 31.5	$241,259.11	$4,596.90	0.01905	73.01
31.5 - 32.5	$205,891.68	$6,072.07	0.02949	71.61
32.5 - 33.5	$145,179.43	$9,032.01	0.06221	69.50
33.5 - 34.5	$96,977.78	$7,706.85	0.07947	65.18
34.5 - 35.5	$54,300.68	$1,308.71	0.02410	60.00
35.5 - 36.5	$32,830.18	$1,525.72	0.04647	58.55

Northern Utilities, Inc.
New Hampshire
380.20 SERVICES - COATED STEEL NOT WRAPPED

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1968 TO 1976

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
36.5 - 37.5	$22,501.50	$0.00	0.00000	55.83
37.5 - 38.5	$15,732.31	$0.00	0.00000	55.83

Northern Utilities, Inc.
New Hampshire
380.30 SERVICES - STEEL COATED & WRAPPED
Original And Smooth Survivor Curves



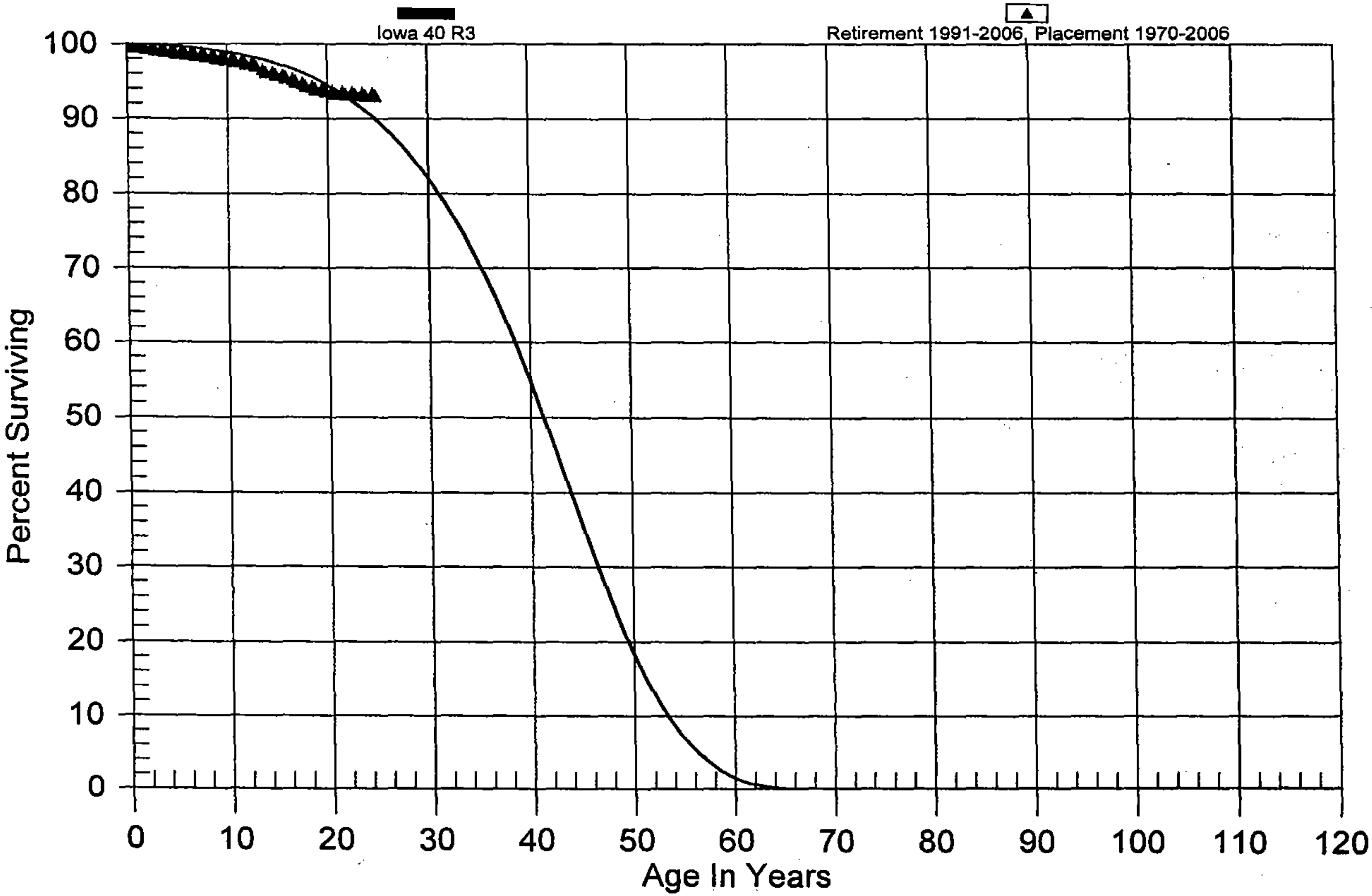
Northern Utilities, Inc.
New Hampshire
380.30 SERVICES - STEEL COATED & WRAPPED

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1977 TO 1982

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$0.00	$0.00	0.00000	100.00
0.5 - 1.5	$0.00	$0.00	0.00000	100.00
1.5 - 2.5	$0.00	$0.00	0.00000	100.00
2.5 - 3.5	$0.00	$0.00	0.00000	100.00
3.5 - 4.5	$0.00	$0.00	0.00000	100.00
4.5 - 5.5	$0.00	$0.00	0.00000	100.00
5.5 - 6.5	$0.00	$0.00	0.00000	100.00
6.5 - 7.5	$0.00	$0.00	0.00000	100.00
7.5 - 8.5	$0.00	$0.00	0.00000	100.00
8.5 - 9.5	$26,259.19	$2,854.06	0.10869	100.00
9.5 - 10.5	$54,630.37	$0.00	0.00000	89.13
10.5 - 11.5	$80,670.47	$884.34	0.01096	89.13
11.5 - 12.5	$136,781.25	$542.70	0.00397	88.15
12.5 - 13.5	$151,108.81	$0.00	0.00000	87.80
13.5 - 14.5	$163,112.12	$426.39	0.00261	87.80
14.5 - 15.5	$162,685.73	$658.65	0.00405	87.57
15.5 - 16.5	$162,027.08	$1,610.86	0.00994	87.22
16.5 - 17.5	$160,416.22	$0.00	0.00000	86.35
17.5 - 18.5	$160,416.22	$1,071.96	0.00668	86.35
18.5 - 19.5	$159,344.26	$0.00	0.00000	85.78
19.5 - 20.5	$159,344.26	$0.00	0.00000	85.78
20.5 - 21.5	$159,344.26	$0.00	0.00000	85.78
21.5 - 22.5	$159,344.26	$5,421.30	0.03402	85.78
22.5 - 23.5	$153,922.96	$580.59	0.00377	82.86
23.5 - 24.5	$153,342.37	$1,953.04	0.01274	82.55
24.5 - 25.5	$128,413.17	$335.65	0.00261	81.49
25.5 - 26.5	$97,945.44	$6,379.29	0.06513	81.28
26.5 - 27.5	$77,810.18	$2,550.89	0.03278	75.99
27.5 - 28.5	$20,504.99	$0.00	0.00000	73.50
28.5 - 29.5	$9,335.25	$0.00	0.00000	73.50

Northern Utilities, Inc.

New Hampshire
380.40 SERVICES - PLASTIC
Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1970 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$17,786,233.04	$6,896.35	0.00039	100.00
0.5 - 1.5	$18,076,201.68	$24,437.72	0.00135	99.96
1.5 - 2.5	$17,707,499.77	$43,219.92	0.00244	99.83
2.5 - 3.5	$17,501,599.24	$24,538.67	0.00140	99.58
3.5 - 4.5	$17,301,287.85	$36,343.63	0.00210	99.44
4.5 - 5.5	$16,634,458.54	$25,244.13	0.00152	99.23
5.5 - 6.5	$16,247,289.96	$27,613.91	0.00170	99.08
6.5 - 7.5	$15,490,952.58	$28,660.75	0.00185	98.91
7.5 - 8.5	$14,673,326.58	$33,875.09	0.00231	98.73
8.5 - 9.5	$13,712,135.79	$21,288.37	0.00155	98.50
9.5 - 10.5	$12,703,075.74	$33,131.19	0.00261	98.35
10.5 - 11.5	$11,683,960.73	$40,881.62	0.00350	98.09
11.5 - 12.5	$11,059,537.68	$32,558.44	0.00294	97.75
12.5 - 13.5	$9,282,999.97	$87,092.26	0.00938	97.46
13.5 - 14.5	$8,410,915.06	$27,908.40	0.00332	96.55
14.5 - 15.5	$7,240,861.24	$26,890.21	0.00371	96.23
15.5 - 16.5	$5,896,331.93	$33,538.01	0.00569	95.87
16.5 - 17.5	$4,511,274.17	$29,366.60	0.00651	95.33
17.5 - 18.5	$3,673,345.50	$15,357.77	0.00418	94.71
18.5 - 19.5	$2,851,923.23	$8,170.82	0.00287	94.31
19.5 - 20.5	$2,189,465.32	$7,165.35	0.00327	94.04
20.5 - 21.5	$1,698,448.17	$2,073.51	0.00122	93.73
21.5 - 22.5	$1,355,162.73	$980.74	0.00072	93.62
22.5 - 23.5	$1,166,304.64	$1,233.40	0.00106	93.55
23.5 - 24.5	$1,022,643.07	$0.00	0.00000	93.45
24.5 - 25.5	$873,168.47	$0.00	0.00000	93.45
25.5 - 26.5	$694,190.21	$0.00	0.00000	93.45
26.5 - 27.5	$553,145.45	$0.00	0.00000	93.45
27.5 - 28.5	$233,943.36	$0.00	0.00000	93.45
28.5 - 29.5	$162,318.50	$0.00	0.00000	93.45
29.5 - 30.5	$91,969.72	$0.00	0.00000	93.45
30.5 - 31.5	$77,857.59	$0.00	0.00000	93.45
31.5 - 32.5	$63,510.89	$0.00	0.00000	93.45
32.5 - 33.5	$41,916.23	$0.00	0.00000	93.45
33.5 - 34.5	$27,949.87	$0.00	0.00000	93.45
34.5 - 35.5	$15,031.43	$0.00	0.00000	93.45
35.5 - 36.5	$3,966.00	$0.00	0.00000	93.45

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Observed Life Table
Retirement Expr. 1992 TO 1996
Placement Years 1970 TO 1996

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$6,138,393.56	$0.00	0.00000	100.00
0.5 - 1.5	$6,325,545.67	$10,981.32	0.00174	100.00
1.5 - 2.5	$6,799,172.82	$28,326.92	0.00417	99.83
2.5 - 3.5	$5,777,113.70	$6,586.75	0.00114	99.41
3.5 - 4.5	$5,675,389.92	$21,042.98	0.00371	99.30
4.5 - 5.5	$5,156,375.69	$11,732.21	0.00228	98.93
5.5 - 6.5	$4,306,302.34	$15,204.63	0.00353	98.70
6.5 - 7.5	$3,234,640.14	$12,466.26	0.00385	98.36
7.5 - 8.5	$2,587,253.37	$2,116.27	0.00082	97.98
8.5 - 9.5	$1,899,274.91	$3,759.96	0.00198	97.90
9.5 - 10.5	$1,378,479.68	$12,043.29	0.00874	97.70
10.5 - 11.5	$1,050,194.41	$6,437.79	0.00613	96.85
11.5 - 12.5	$839,609.88	$6,352.39	0.00757	96.26
12.5 - 13.5	$972,404.54	$4,190.13	0.00431	95.53
13.5 - 14.5	$907,729.70	$4,353.35	0.00480	95.12
14.5 - 15.5	$822,838.97	$9,867.90	0.01199	94.66
15.5 - 16.5	$647,719.58	$4,456.66	0.00688	93.52
16.5 - 17.5	$511,275.98	$13,094.46	0.02561	92.88
17.5 - 18.5	$194,047.97	$0.00	0.00000	90.50
18.5 - 19.5	$134,798.02	$0.00	0.00000	90.50
19.5 - 20.5	$76,938.29	$0.00	0.00000	90.50
20.5 - 21.5	$73,891.59	$0.00	0.00000	90.50
21.5 - 22.5	$63,510.89	$0.00	0.00000	90.50
22.5 - 23.5	$41,916.23	$0.00	0.00000	90.50
23.5 - 24.5	$27,949.87	$0.00	0.00000	90.50
24.5 - 25.5	$15,031.43	$0.00	0.00000	90.50
25.5 - 26.5	$3,966.00	$0.00	0.00000	90.50
26.5 - 27.5	$0.00	$0.00	0.00000	90.50
27.5 - 28.5	$0.00	$0.00	0.00000	90.50
28.5 - 29.5	$0.00	$0.00	0.00000	90.50
29.5 - 30.5	$0.00	$0.00	0.00000	90.50
30.5 - 31.5	$0.00	$0.00	0.00000	90.50
31.5 - 32.5	$0.00	$0.00	0.00000	90.50
32.5 - 33.5	$0.00	$0.00	0.00000	90.50
33.5 - 34.5	$0.00	$0.00	0.00000	90.50
34.5 - 35.5	$0.00	$0.00	0.00000	90.50
35.5 - 36.5	$0.00	$0.00	0.00000	90.50

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Observed Life Table
Retirement Expr. 1997 TO 2001
Placement Years 1970 TO 2001

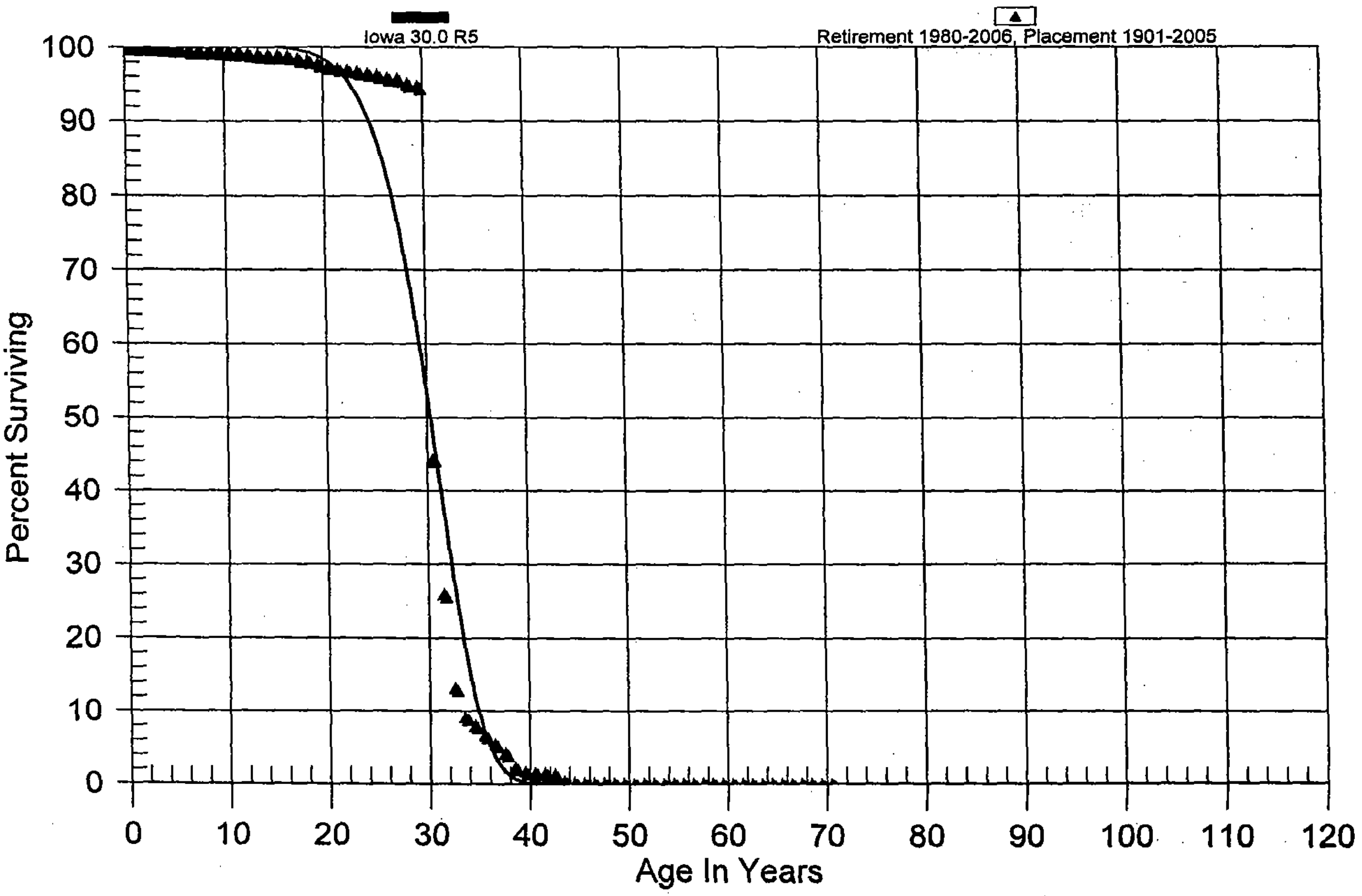
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$4,921,011.04	$0.00	0.00000	100.00
0.5 - 1.5	$5,356,302.68	$10,135.64	0.00189	100.00
1.5 - 2.5	$5,343,515.02	$6,629.55	0.00124	99.81
2.5 - 3.5	$6,238,269.32	$6,154.65	0.00099	99.69
3.5 - 4.5	$6,085,401.86	$11,129.94	0.00183	99.59
4.5 - 5.5	$6,071,930.86	$7,668.00	0.00126	99.41
5.5 - 6.5	$6,256,695.51	$3,595.83	0.00057	99.28
6.5 - 7.5	$6,730,321.41	$4,052.98	0.00060	99.22
7.5 - 8.5	$5,720,343.45	$16,475.69	0.00288	99.16
8.5 - 9.5	$5,612,700.04	$10,163.35	0.00181	98.88
9.5 - 10.5	$5,105,949.71	$11,283.83	0.00221	98.70
10.5 - 11.5	$4,253,983.71	$8,236.27	0.00194	98.48
11.5 - 12.5	$3,198,214.43	$4,388.67	0.00137	98.29
12.5 - 13.5	$2,559,442.22	$12,924.54	0.00505	98.16
13.5 - 14.5	$1,859,133.54	$6,546.72	0.00352	97.66
14.5 - 15.5	$1,334,275.88	$6,026.33	0.00452	97.32
15.5 - 16.5	$1,018,122.52	$5,034.54	0.00494	96.88
16.5 - 17.5	$812,527.33	$3,540.74	0.00436	96.40
17.5 - 18.5	$946,837.45	$6,411.28	0.00677	95.98
18.5 - 19.5	$868,511.98	$3,448.75	0.00397	95.33
19.5 - 20.5	$786,366.80	$3,217.58	0.00409	94.95
20.5 - 21.5	$618,283.09	$969.73	0.00157	94.56
21.5 - 22.5	$490,615.30	$980.74	0.00200	94.41
22.5 - 23.5	$192,027.13	$0.00	0.00000	94.22
23.5 - 24.5	$134,368.63	$0.00	0.00000	94.22
24.5 - 25.5	$76,938.29	$0.00	0.00000	94.22
25.5 - 26.5	$73,891.59	$0.00	0.00000	94.22
26.5 - 27.5	$63,510.89	$0.00	0.00000	94.22
27.5 - 28.5	$41,916.23	$0.00	0.00000	94.22
28.5 - 29.5	$27,949.87	$0.00	0.00000	94.22
29.5 - 30.5	$15,031.43	$0.00	0.00000	94.22
30.5 - 31.5	$3,966.00	$0.00	0.00000	94.22
31.5 - 32.5	$0.00	$0.00	0.00000	94.22
32.5 - 33.5	$0.00	$0.00	0.00000	94.22
33.5 - 34.5	$0.00	$0.00	0.00000	94.22
34.5 - 35.5	$0.00	$0.00	0.00000	94.22
35.5 - 36.5	$0.00	$0.00	0.00000	94.22

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Observed Life Table
Retirement Expr. 2002 TO 2006
Placement Years 1970 TO 2006

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$5,375,285.21	$6,896.35	0.00128	100.00
0.5 - 1.5	$4,958,072.06	$2,883.48	0.00058	99.87
1.5 - 2.5	$4,700,246.37	$5,836.53	0.00124	99.81
2.5 - 3.5	$4,631,859.11	$11,797.27	0.00255	99.69
3.5 - 4.5	$4,863,084.09	$4,170.71	0.00086	99.44
4.5 - 5.5	$4,899,024.35	$5,123.22	0.00105	99.35
5.5 - 6.5	$5,319,582.52	$8,813.45	0.00166	99.25
6.5 - 7.5	$5,318,469.03	$12,141.51	0.00228	99.08
7.5 - 8.5	$6,208,559.57	$14,093.40	0.00227	98.86
8.5 - 9.5	$6,045,322.19	$7,365.06	0.00122	98.63
9.5 - 10.5	$6,034,525.14	$9,804.07	0.00162	98.51
10.5 - 11.5	$6,226,235.84	$26,207.56	0.00421	98.35
11.5 - 12.5	$6,685,638.73	$21,817.38	0.00326	97.94
12.5 - 13.5	$5,663,469.95	$69,977.59	0.01236	97.62
13.5 - 14.5	$5,573,273.65	$17,008.33	0.00305	96.41
14.5 - 15.5	$5,068,041.32	$10,995.98	0.00217	96.12
15.5 - 16.5	$4,216,143.13	$24,046.81	0.00570	95.91
16.5 - 17.5	$3,165,876.20	$12,731.40	0.00402	95.36
17.5 - 18.5	$2,518,493.72	$8,946.49	0.00355	94.98
18.5 - 19.5	$1,835,694.79	$4,722.07	0.00257	94.64
19.5 - 20.5	$1,315,094.80	$3,947.77	0.00300	94.40
20.5 - 21.5	$1,002,307.49	$1,103.78	0.00110	94.11
21.5 - 22.5	$801,036.54	$0.00	0.00000	94.01
22.5 - 23.5	$932,361.28	$1,233.40	0.00132	94.01
23.5 - 24.5	$860,324.57	$0.00	0.00000	93.89
24.5 - 25.5	$781,198.75	$0.00	0.00000	93.89
25.5 - 26.5	$616,332.62	$0.00	0.00000	93.89
26.5 - 27.5	$489,634.56	$0.00	0.00000	93.89
27.5 - 28.5	$192,027.13	$0.00	0.00000	93.89
28.5 - 29.5	$134,368.63	$0.00	0.00000	93.89
29.5 - 30.5	$76,938.29	$0.00	0.00000	93.89
30.5 - 31.5	$73,891.59	$0.00	0.00000	93.89
31.5 - 32.5	$63,510.89	$0.00	0.00000	93.89
32.5 - 33.5	$41,916.23	$0.00	0.00000	93.89
33.5 - 34.5	$27,949.87	$0.00	0.00000	93.89
34.5 - 35.5	$15,031.43	$0.00	0.00000	93.89
35.5 - 36.5	$3,966.00	$0.00	0.00000	93.89

Northern Utilities, Inc.
New Hampshire
381.00 METERS
Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
381.00 METERS

Observed Life Table
Retirement Expr. 1980 TO 2006
Placement Years 1901 TO 2005

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$2,029,980.25	$0.00	0.00000	100.00
0.5 - 1.5	$2,163,562.19	$788.03	0.00036	100.00
1.5 - 2.5	$2,100,372.27	$1,322.61	0.00063	99.96
2.5 - 3.5	$2,122,576.29	$522.04	0.00025	99.90
3.5 - 4.5	$2,133,191.77	$450.48	0.00021	99.88
4.5 - 5.5	$2,115,442.95	$1,392.95	0.00066	99.85
5.5 - 6.5	$2,108,418.68	$4,101.41	0.00195	99.79
6.5 - 7.5	$2,113,253.17	$821.18	0.00039	99.60
7.5 - 8.5	$2,061,836.75	$1,799.51	0.00087	99.56
8.5 - 9.5	$2,075,091.71	$1,213.69	0.00058	99.47
9.5 - 10.5	$1,948,855.82	$1,065.24	0.00055	99.41
10.5 - 11.5	$1,920,276.43	$2,004.17	0.00104	99.36
11.5 - 12.5	$1,849,271.79	$3,174.24	0.00172	99.25
12.5 - 13.5	$1,734,104.78	$1,848.72	0.00107	99.08
13.5 - 14.5	$1,712,570.30	$1,397.29	0.00082	98.98
14.5 - 15.5	$1,701,184.14	$774.18	0.00046	98.90
15.5 - 16.5	$1,512,343.73	$1,420.06	0.00094	98.85
16.5 - 17.5	$1,301,390.83	$4,365.69	0.00335	98.76
17.5 - 18.5	$1,210,817.52	$2,414.36	0.00199	98.43
18.5 - 19.5	$1,163,597.49	$5,637.07	0.00484	98.23
19.5 - 20.5	$1,086,146.51	$4,024.59	0.00371	97.76
20.5 - 21.5	$1,059,936.40	$3,211.59	0.00303	97.39
21.5 - 22.5	$961,004.79	$1,909.46	0.00199	97.10
22.5 - 23.5	$947,070.10	$1,985.85	0.00210	96.91
23.5 - 24.5	$895,823.81	$2,261.34	0.00252	96.70
24.5 - 25.5	$843,393.80	$2,310.20	0.00274	96.46
25.5 - 26.5	$574,966.48	$2,213.29	0.00385	96.19
26.5 - 27.5	$572,414.36	$548.10	0.00096	95.82
27.5 - 28.5	$426,516.26	$3,215.82	0.00754	95.73
28.5 - 29.5	$311,853.72	$1,010.62	0.00324	95.01
29.5 - 30.5	$220,936.46	$117,317.72	0.53100	94.70
30.5 - 31.5	$51,079.88	$21,242.73	0.41587	44.41
31.5 - 32.5	$11,103.15	$5,465.05	0.49221	25.94
32.5 - 33.5	$6,991.44	$2,111.77	0.30205	13.17
33.5 - 34.5	$7,752.06	$1,039.83	0.13414	9.19
34.5 - 35.5	$8,038.33	$1,394.96	0.17354	7.96
35.5 - 36.5	$6,995.41	$1,268.15	0.18128	6.58

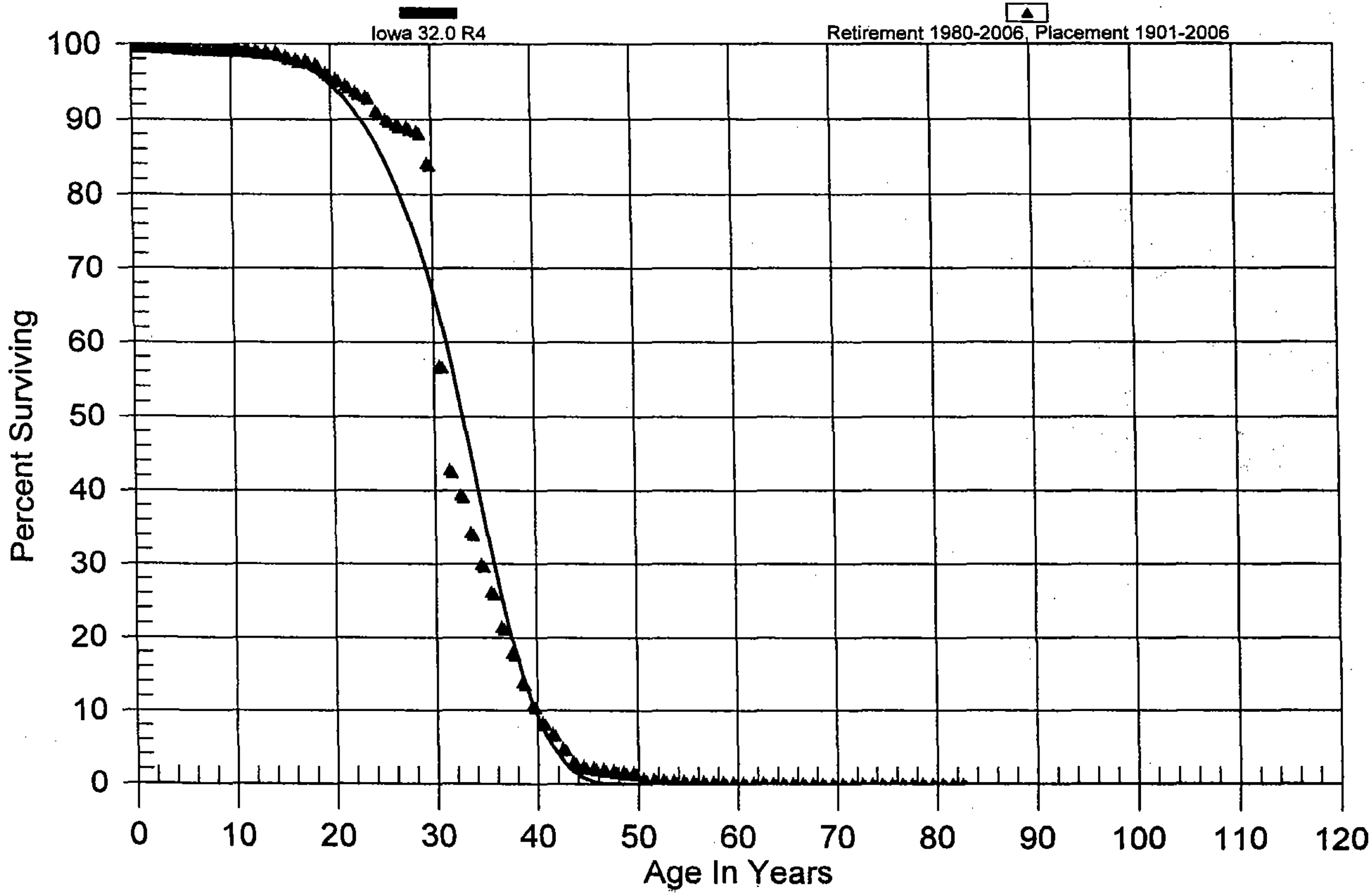
Northern Utilities, Inc.
New Hampshire
381.00 METERS

Observed Life Table
Retirement Expr. 1980 TO 2006
Placement Years 1901 TO 2005

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
36.5 - 37.5	$5,956.38	$1,365.39	0.22923	5.39
37.5 - 38.5	$5,882.47	$2,710.56	0.46079	4.15
38.5 - 39.5	$5,374.15	$1,380.18	0.25682	2.24
39.5 - 40.5	$4,241.76	$323.26	0.07621	1.66
40.5 - 41.5	$4,843.93	$235.34	0.04858	1.54
41.5 - 42.5	$3,717.00	$399.50	0.10748	1.46
42.5 - 43.5	$3,365.35	$2,336.34	0.69423	1.31
43.5 - 44.5	$1,059.74	$811.84	0.76607	0.40
44.5 - 45.5	$253.35	$73.13	0.28865	0.09
45.5 - 46.5	$226.51	$9.34	0.04123	0.07
46.5 - 47.5	$217.17	$15.95	0.07344	0.06
47.5 - 48.5	$201.22	$5.84	0.02902	0.06
48.5 - 49.5	$251.01	$24.89	0.09916	0.06
49.5 - 50.5	$4,067.52	$3,760.86	0.92461	0.05
50.5 - 51.5	$434.65	$169.61	0.39022	0.00
51.5 - 52.5	$356.07	$240.52	0.67549	0.00
52.5 - 53.5	$521.28	$94.53	0.18134	0.00
53.5 - 54.5	$506.11	$409.62	0.80935	0.00
54.5 - 55.5	$175.07	$88.69	0.50660	0.00
55.5 - 56.5	$131.89	$80.53	0.61058	0.00
56.5 - 57.5	$109.32	$49.41	0.45198	0.00
57.5 - 58.5	$170.01	$33.45	0.19675	0.00
58.5 - 59.5	$194.53	$64.97	0.33398	0.00
59.5 - 60.5	$134.23	$22.18	0.16524	0.00
60.5 - 61.5	$145.89	$9.73	0.06669	0.00
61.5 - 62.5	$431.41	$75.08	0.17403	0.00
62.5 - 63.5	$393.67	$327.15	0.83103	0.00
63.5 - 64.5	$103.48	$44.35	0.42859	0.00
64.5 - 65.5	$91.42	$59.13	0.64680	0.00
65.5 - 66.5	$48.63	$32.29	0.66399	0.00
66.5 - 67.5	$60.30	$16.34	0.27098	0.00
67.5 - 68.5	$85.97	$43.96	0.51134	0.00
68.5 - 69.5	$89.08	$42.01	0.47160	0.00
69.5 - 70.5	$411.18	$47.07	0.11448	0.00

Northern Utilities, Inc.

New Hampshire
382.00 METER INSTALLATIONS
Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Observed Life Table
Retirement Expr. 1980 TO 2006
Placement Years 1901 TO 2006

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$9,127,518.51	$0.00	0.00000	100.00
0.5 - 1.5	$9,091,139.39	$1,566.92	0.00017	100.00
1.5 - 2.5	$7,810,826.68	$5,881.30	0.00075	99.98
2.5 - 3.5	$7,294,820.97	$1,594.38	0.00022	99.91
3.5 - 4.5	$6,758,312.61	$3,364.79	0.00050	99.89
4.5 - 5.5	$6,144,716.66	$2,606.45	0.00042	99.84
5.5 - 6.5	$5,699,752.17	$6,182.38	0.00108	99.79
6.5 - 7.5	$5,197,314.12	$1,739.45	0.00033	99.69
7.5 - 8.5	$4,643,249.59	$1,725.07	0.00037	99.65
8.5 - 9.5	$4,106,456.14	$2,503.75	0.00061	99.61
9.5 - 10.5	$3,664,601.24	$3,141.14	0.00086	99.55
10.5 - 11.5	$3,288,987.48	$2,484.80	0.00076	99.47
11.5 - 12.5	$2,941,053.42	$3,905.58	0.00133	99.39
12.5 - 13.5	$2,525,310.88	$2,772.68	0.00110	99.26
13.5 - 14.5	$2,170,449.60	$2,505.01	0.00115	99.15
14.5 - 15.5	$1,818,759.52	$8,838.93	0.00486	99.04
15.5 - 16.5	$1,479,636.35	$6,657.00	0.00450	98.56
16.5 - 17.5	$1,151,797.95	$1,573.71	0.00137	98.11
17.5 - 18.5	$921,640.26	$4,870.30	0.00528	97.98
18.5 - 19.5	$771,633.32	$9,090.92	0.01178	97.46
19.5 - 20.5	$660,654.95	$5,459.79	0.00826	96.31
20.5 - 21.5	$561,807.09	$5,260.98	0.00936	95.52
21.5 - 22.5	$513,107.05	$4,485.09	0.00874	94.62
22.5 - 23.5	$479,808.43	$3,213.81	0.00670	93.80
23.5 - 24.5	$444,648.89	$9,853.71	0.02216	93.17
24.5 - 25.5	$396,196.71	$4,505.07	0.01137	91.10
25.5 - 26.5	$348,200.38	$2,665.18	0.00765	90.07
26.5 - 27.5	$308,149.35	$1,188.29	0.00386	89.38
27.5 - 28.5	$256,433.07	$1,641.60	0.00640	89.03
28.5 - 29.5	$234,679.62	$11,256.82	0.04797	88.46
29.5 - 30.5	$210,782.32	$68,229.24	0.32370	84.22
30.5 - 31.5	$130,628.17	$32,373.68	0.24783	56.96
31.5 - 32.5	$88,541.79	$6,921.61	0.07817	42.84
32.5 - 33.5	$84,625.80	$11,079.62	0.13092	39.49
33.5 - 34.5	$78,293.52	$9,812.64	0.12533	34.32
34.5 - 35.5	$70,786.99	$8,873.32	0.12535	30.02
35.5 - 36.5	$62,716.63	$11,409.45	0.18192	26.26

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS
Observed Life Table
Retirement Expr. 1980 TO 2006
Placement Years 1901 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
36.5 - 37.5	$51,901.43	$8,381.33	0.16149	21.48
37.5 - 38.5	$45,789.00	$10,343.02	0.22588	18.01
38.5 - 39.5	$38,964.38	$8,869.71	0.22764	13.94
39.5 - 40.5	$30,483.88	$6,594.72	0.21633	10.77
40.5 - 41.5	$25,589.91	$4,774.54	0.18658	8.44
41.5 - 42.5	$19,548.20	$5,713.08	0.29226	6.86
42.5 - 43.5	$14,160.27	$5,417.31	0.38257	4.86
43.5 - 44.5	$9,023.37	$1,700.21	0.18842	3.00
44.5 - 45.5	$7,567.43	$552.68	0.07303	2.43
45.5 - 46.5	$7,250.92	$632.93	0.08729	2.26
46.5 - 47.5	$6,867.99	$588.77	0.08573	2.06
47.5 - 48.5	$6,529.22	$434.47	0.06654	1.88
48.5 - 49.5	$6,416.96	$478.08	0.07450	1.76
49.5 - 50.5	$12,212.06	$6,242.01	0.51113	1.63
50.5 - 51.5	$6,416.43	$907.93	0.14150	0.80
51.5 - 52.5	$5,901.47	$1,019.44	0.17274	0.68
52.5 - 53.5	$5,764.49	$754.87	0.13095	0.56
53.5 - 54.5	$5,379.36	$869.12	0.16157	0.49
54.5 - 55.5	$4,883.66	$362.52	0.07423	0.41
55.5 - 56.5	$4,742.63	$364.57	0.07687	0.38
56.5 - 57.5	$4,556.31	$363.65	0.07981	0.35
57.5 - 58.5	$4,394.48	$275.62	0.06272	0.32
58.5 - 59.5	$4,209.89	$527.80	0.12537	0.30
59.5 - 60.5	$3,689.42	$162.04	0.04392	0.27
60.5 - 61.5	$3,580.54	$270.48	0.07554	0.25
61.5 - 62.5	$3,773.81	$355.27	0.09414	0.23
62.5 - 63.5	$3,477.20	$763.46	0.21956	0.21
63.5 - 64.5	$2,771.78	$481.64	0.17377	0.17
64.5 - 65.5	$2,340.85	$356.94	0.15248	0.14
65.5 - 66.5	$2,009.57	$290.36	0.14449	0.12
66.5 - 67.5	$1,788.25	$582.92	0.32597	0.10
67.5 - 68.5	$1,271.32	$392.36	0.30862	0.07
68.5 - 69.5	$952.89	$357.71	0.37539	0.05
69.5 - 70.5	$1,193.12	$319.03	0.26739	0.03
70.5 - 71.5	$874.09	$812.63	0.92969	0.02
71.5 - 72.5	$61.46	$35.41	0.57615	0.00
72.5 - 73.5	$36.44	$0.00	0.00000	0.00

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Observed Life Table
Retirement Expr. 1980 TO 2006
Placement Years 1901 TO 2006

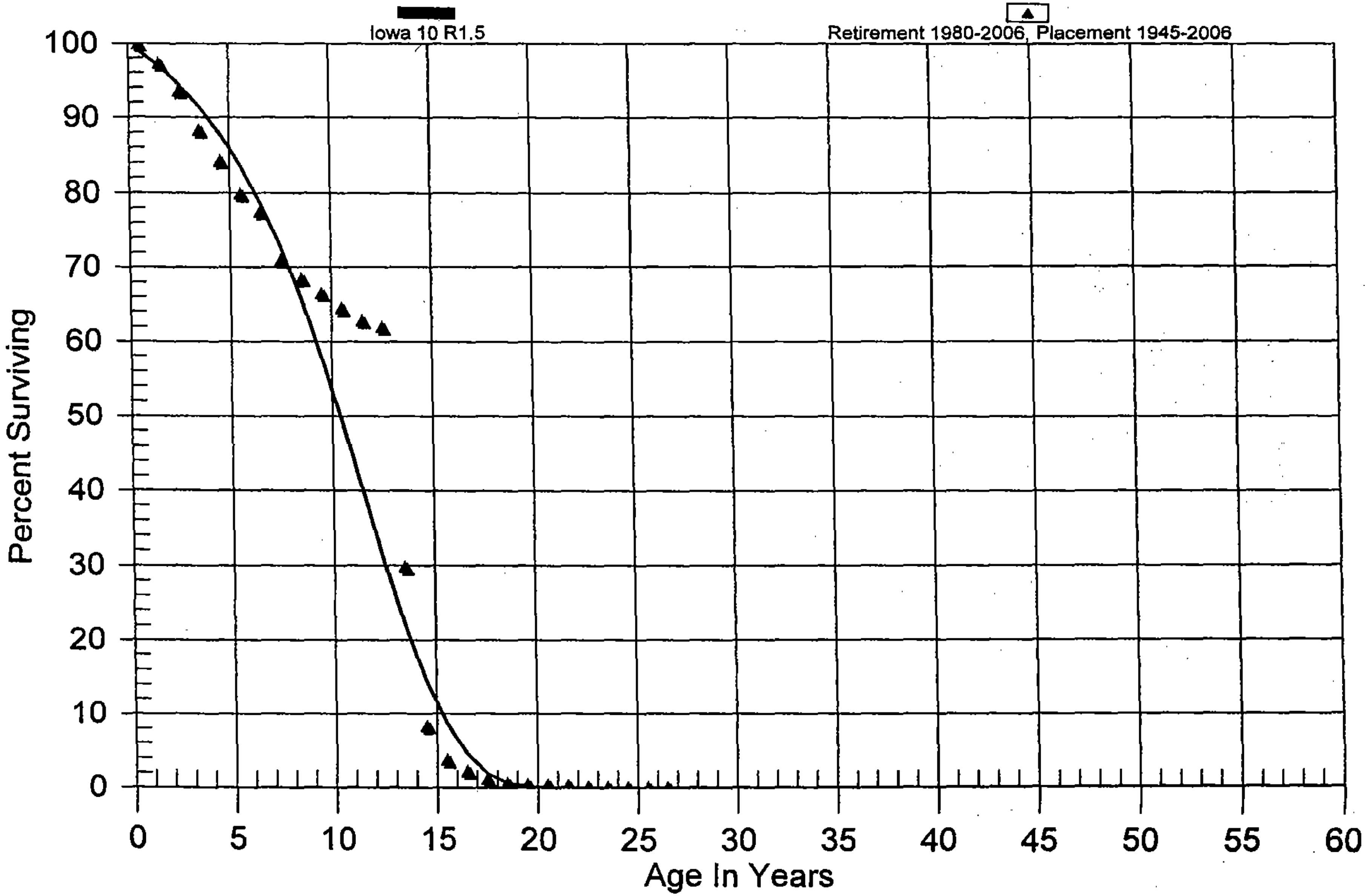
Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
73.5 - 74.5	$36.44	$10.39	0.28513	0.00
74.5 - 75.5	$26.05	$0.00	0.00000	0.00
75.5 - 76.5	$26.05	$0.00	0.00000	0.00
76.5 - 77.5	$26.05	$0.00	0.00000	0.00
77.5 - 78.5	$26.05	$0.00	0.00000	0.00
78.5 - 79.5	$36.44	$0.00	0.00000	0.00
79.5 - 80.5	$36.44	$0.00	0.00000	0.00
80.5 - 81.5	$36.44	$0.00	0.00000	0.00
81.5 - 82.5	$36.44	$10.39	0.28513	0.00

Northern Utilities, Inc.

New Hampshire

386.12 (386.1 &.2) MISC. PROP ON CUST'S PREM. (WH & CB)

Original And Smooth Survivor Curves

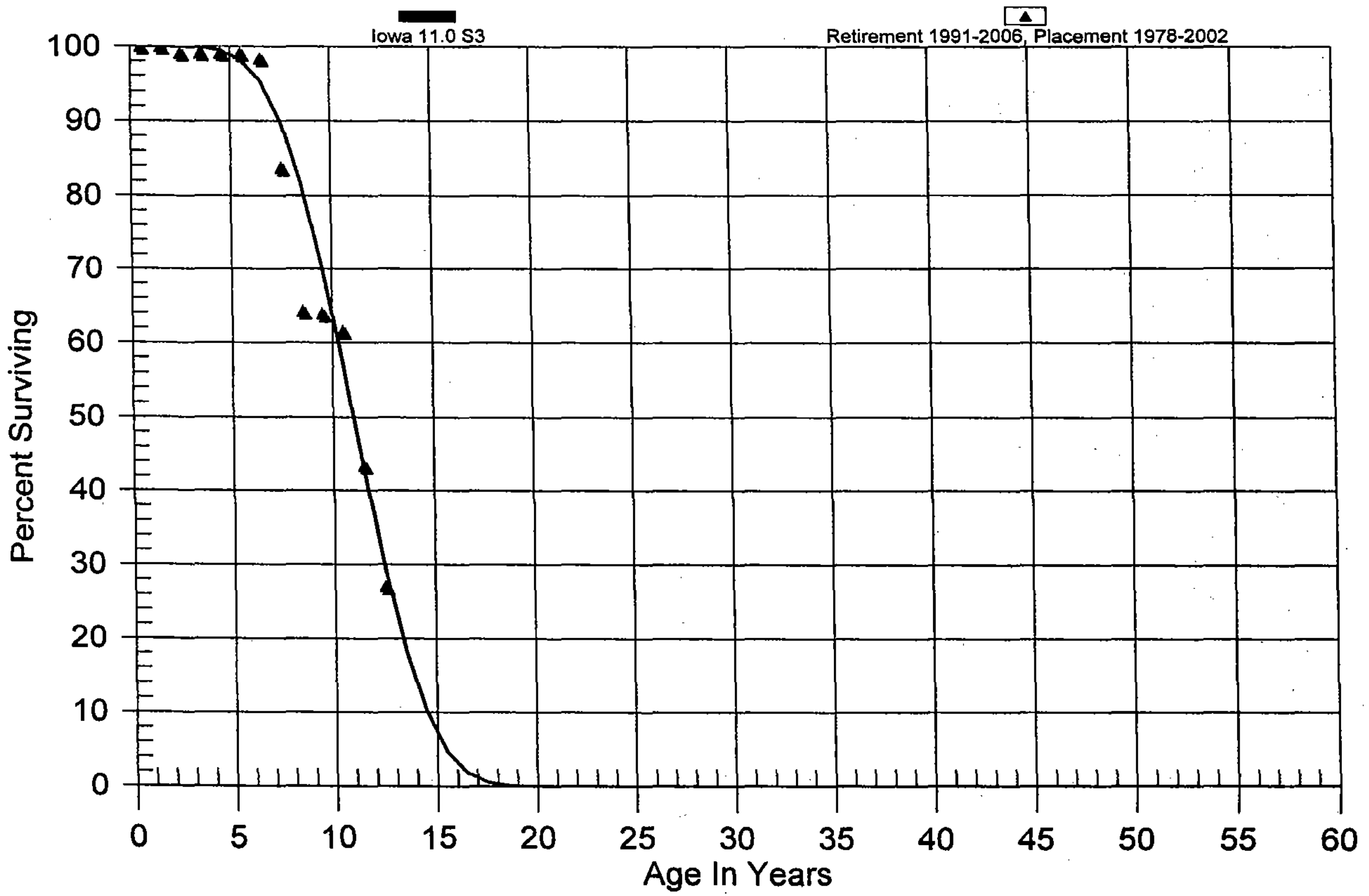


Northern Utilities, Inc.
New Hampshire
386.12 (386.1 &.2) MISC. PROP ON CUST'S PREM. (WH & CB)

Observed Life Table
Retirement Expr. 1980 TO 2006
Placement Years 1945 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$4,010,369.21	$675.00	0.00017	100.00
0.5 - 1.5	$3,960,179.44	$105,388.17	0.02661	99.98
1.5 - 2.5	$3,798,486.19	$145,809.96	0.03839	97.32
2.5 - 3.5	$3,581,982.48	$203,763.40	0.05689	93.59
3.5 - 4.5	$3,332,803.20	$151,104.12	0.04534	88.26
4.5 - 5.5	$3,094,392.27	$159,619.64	0.05158	84.26
5.5 - 6.5	$2,842,358.38	$83,410.82	0.02935	79.91
6.5 - 7.5	$2,601,843.25	$220,970.82	0.08493	77.57
7.5 - 8.5	$2,302,579.66	$80,989.05	0.03517	70.98
8.5 - 9.5	$2,144,513.16	$62,242.43	0.02902	68.48
9.5 - 10.5	$2,004,850.16	$62,351.62	0.03110	66.50
10.5 - 11.5	$1,803,767.29	$46,666.11	0.02587	64.43
11.5 - 12.5	$1,723,500.97	$22,986.48	0.01334	62.76
12.5 - 13.5	$1,575,171.49	$815,613.19	0.51779	61.93
13.5 - 14.5	$763,090.30	$549,372.52	0.71993	29.86
14.5 - 15.5	$217,201.78	$121,577.85	0.55975	8.36
15.5 - 16.5	$101,950.93	$38,700.22	0.37960	3.68
16.5 - 17.5	$63,494.71	$32,152.54	0.50638	2.28
17.5 - 18.5	$32,235.17	$12,937.29	0.40134	1.13
18.5 - 19.5	$29,107.88	$9,451.54	0.32471	0.68
19.5 - 20.5	$33,175.34	$3,733.16	0.11253	0.46
20.5 - 21.5	$37,555.18	$9,726.00	0.25898	0.40
21.5 - 22.5	$28,521.18	$19,047.18	0.66783	0.30
22.5 - 23.5	$9,881.00	$8,972.00	0.90801	0.10
23.5 - 24.5	$1,942.00	$494.00	0.25438	0.01
24.5 - 25.5	$7,805.00	$206.00	0.02639	0.01
25.5 - 26.5	$7,599.00	$467.00	0.06146	0.01

Northern Utilities, Inc.
New Hampshire
391.10 (391.10) OFFICE FURN & EQ-UNSPECIFIED
Original And Smooth Survivor Curves



Northern Utilities, Inc.

New Hampshire

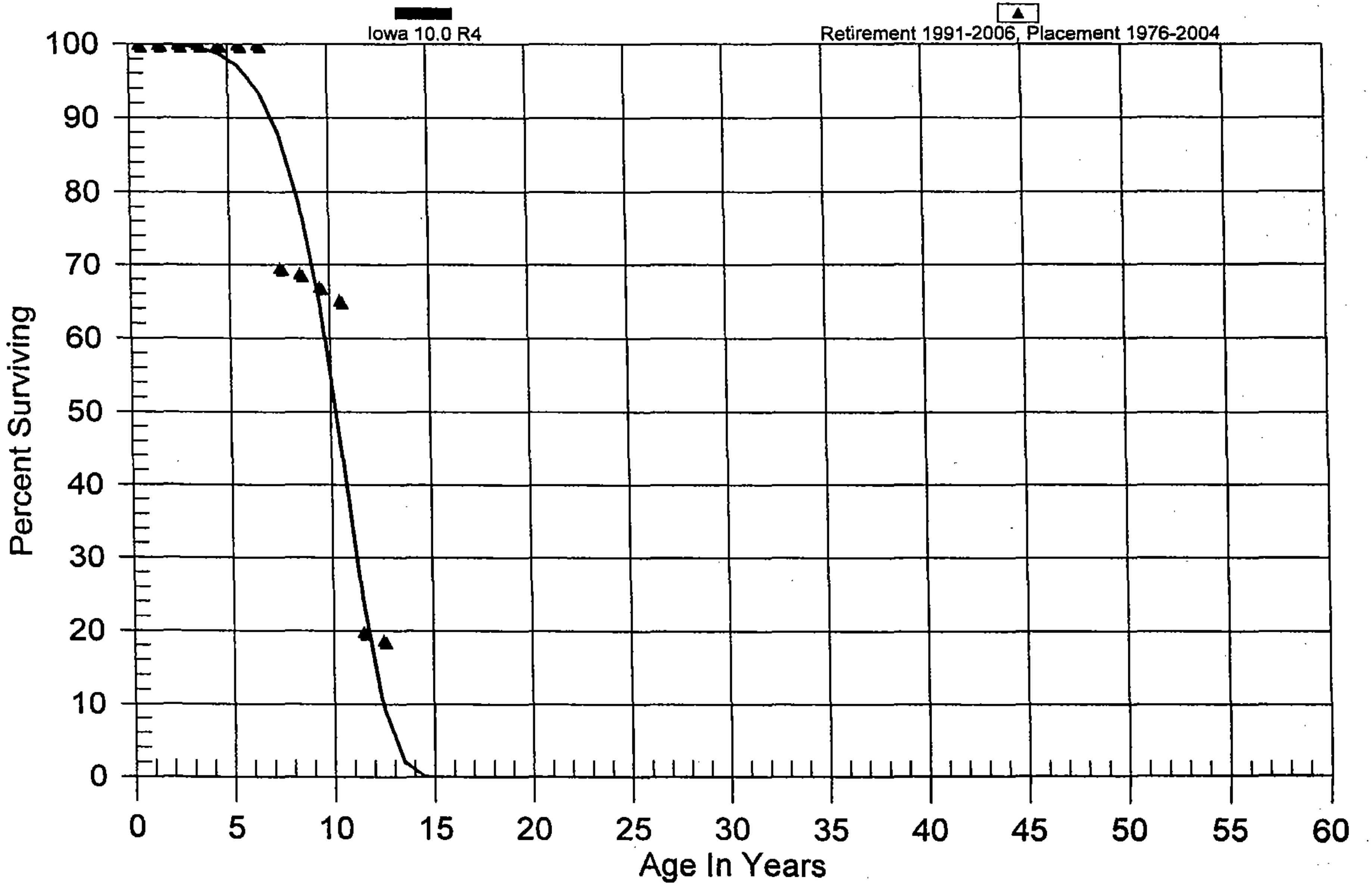
391.10 (391.10) OFFICE FURN & EQ-UNSPECIFIED

Observed Life Table

Retirement Expr. 1991 TO 2006
Placement Years 1978 TO 2002

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$962,806.33	$0.00	0.00000	100.00
0.5 - 1.5	$987,801.78	$0.00	0.00000	100.00
1.5 - 2.5	$1,000,652.11	$8,383.32	0.00838	100.00
2.5 - 3.5	$1,162,793.49	$0.00	0.00000	99.16
3.5 - 4.5	$1,163,377.49	$584.00	0.00050	99.16
4.5 - 5.5	$1,095,000.85	$601.66	0.00055	99.11
5.5 - 6.5	$1,099,968.94	$8,572.57	0.00779	99.06
6.5 - 7.5	$1,091,936.37	$162,049.65	0.14841	98.29
7.5 - 8.5	$899,132.61	$209,071.43	0.23253	83.70
8.5 - 9.5	$675,646.31	$3,518.83	0.00521	64.24
9.5 - 10.5	$645,208.25	$23,620.20	0.03661	63.90
10.5 - 11.5	$548,966.92	$161,853.83	0.29483	61.56
11.5 - 12.5	$99,403.96	$37,530.45	0.37755	43.41

Northern Utilities, Inc.
New Hampshire
391.11 (391.10 & 20) OFFICE FURN & EQ-DATA HANDLING EQ
Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
391.11 (391.10 & 20) OFFICE FURN & EQ-DATA HANDLING EQ

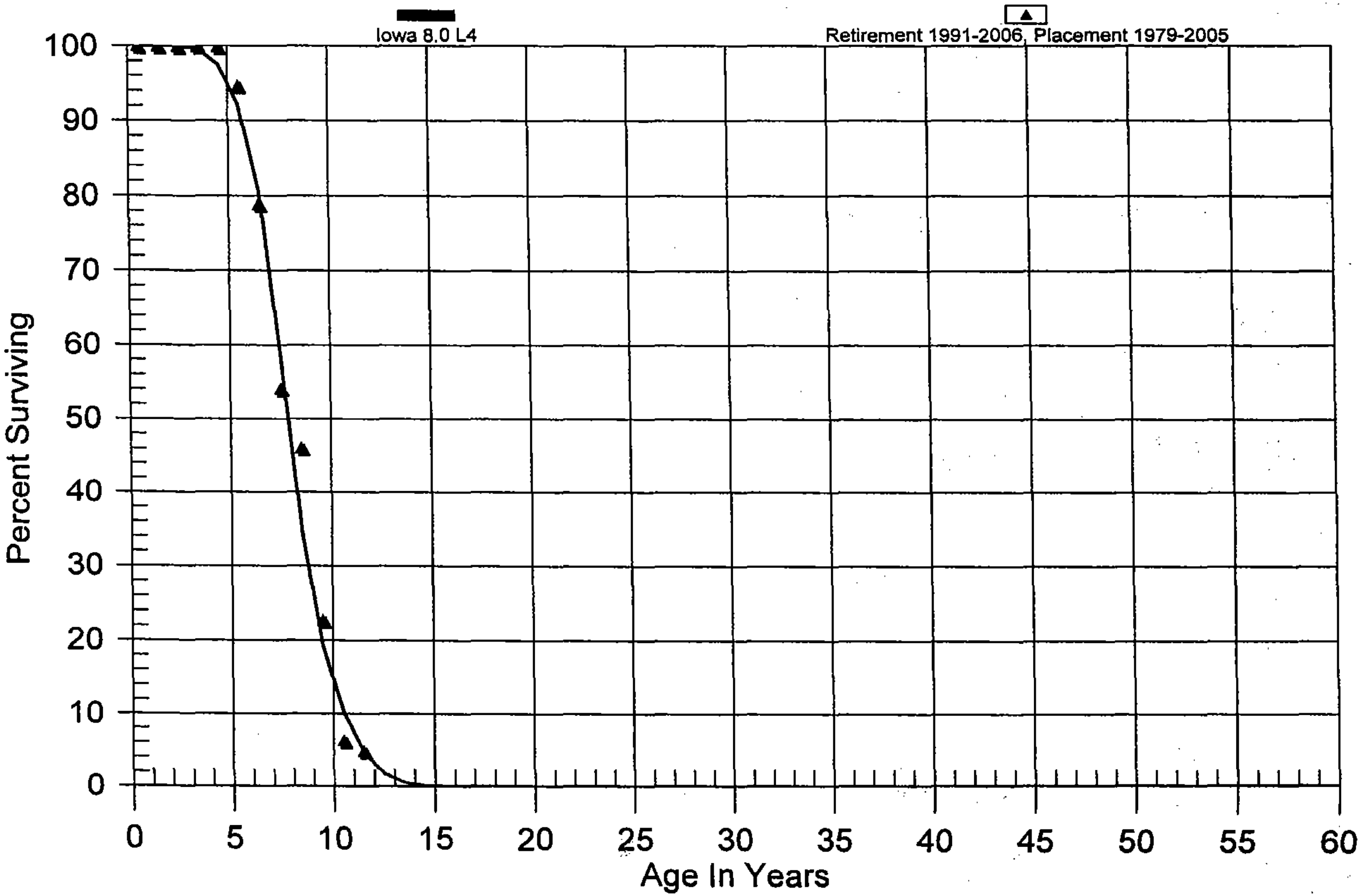
Observed Life Table

Retirement Expr. 1991 TO 2006
Placement Years 1976 TO 2004

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$48,648.00	$0.00	0.00000	100.00
0.5 - 1.5	$68,553.65	$0.00	0.00000	100.00
1.5 - 2.5	$68,553.65	$0.00	0.00000	100.00
2.5 - 3.5	$63,388.15	$0.00	0.00000	100.00
3.5 - 4.5	$63,388.15	$0.00	0.00000	100.00
4.5 - 5.5	$63,388.15	$0.00	0.00000	100.00
5.5 - 6.5	$63,917.08	$0.00	0.00000	100.00
6.5 - 7.5	$63,917.08	$19,422.00	0.30386	100.00
7.5 - 8.5	$45,490.08	$528.93	0.01163	69.61
8.5 - 9.5	$44,961.15	$1,200.00	0.02669	68.80
9.5 - 10.5	$43,761.15	$1,200.00	0.02742	66.97
10.5 - 11.5	$42,561.15	$29,559.73	0.69452	65.13
11.5 - 12.5	$13,876.42	$875.00	0.06306	19.90

Northern Utilities, Inc.

New Hampshire
391.12 (391.30) INFORMATION SYSTEMS
Original And Smooth Survivor Curves

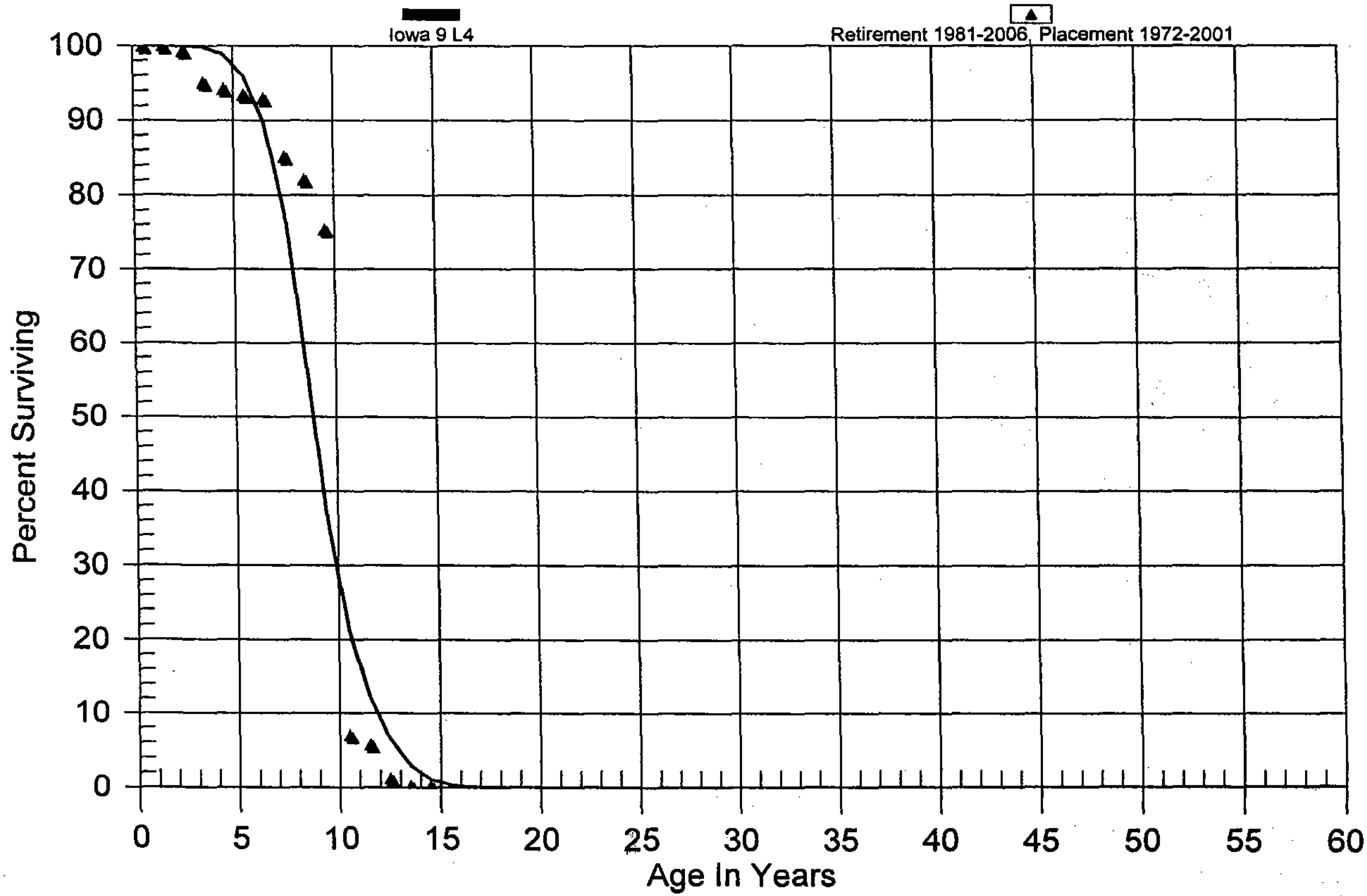


Northern Utilities, Inc.
New Hampshire
391.12 (391.30) INFORMATION SYSTEMS
Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1979 TO 2005

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$1,193,309.04	$0.00	0.00000	100.00
0.5 - 1.5	$1,212,879.39	$0.00	0.00000	100.00
1.5 - 2.5	$1,155,156.64	$0.00	0.00000	100.00
2.5 - 3.5	$1,234,166.57	$0.00	0.00000	100.00
3.5 - 4.5	$1,206,582.61	$1,182.60	0.00098	100.00
4.5 - 5.5	$1,198,102.21	$62,214.43	0.05193	99.90
5.5 - 6.5	$1,135,887.78	$189,641.58	0.16695	94.71
6.5 - 7.5	$952,035.11	$299,393.63	0.31448	78.90
7.5 - 8.5	$657,961.10	$96,957.82	0.14736	54.09
8.5 - 9.5	$567,048.45	$287,479.31	0.50697	46.12
9.5 - 10.5	$297,687.92	$215,724.53	0.72467	22.74
10.5 - 11.5	$94,302.23	$22,115.75	0.23452	6.26

Northern Utilities, Inc.

New Hampshire
392.00 TRANSPORTATION EQUIPMENT
Original And Smooth Survivor Curves



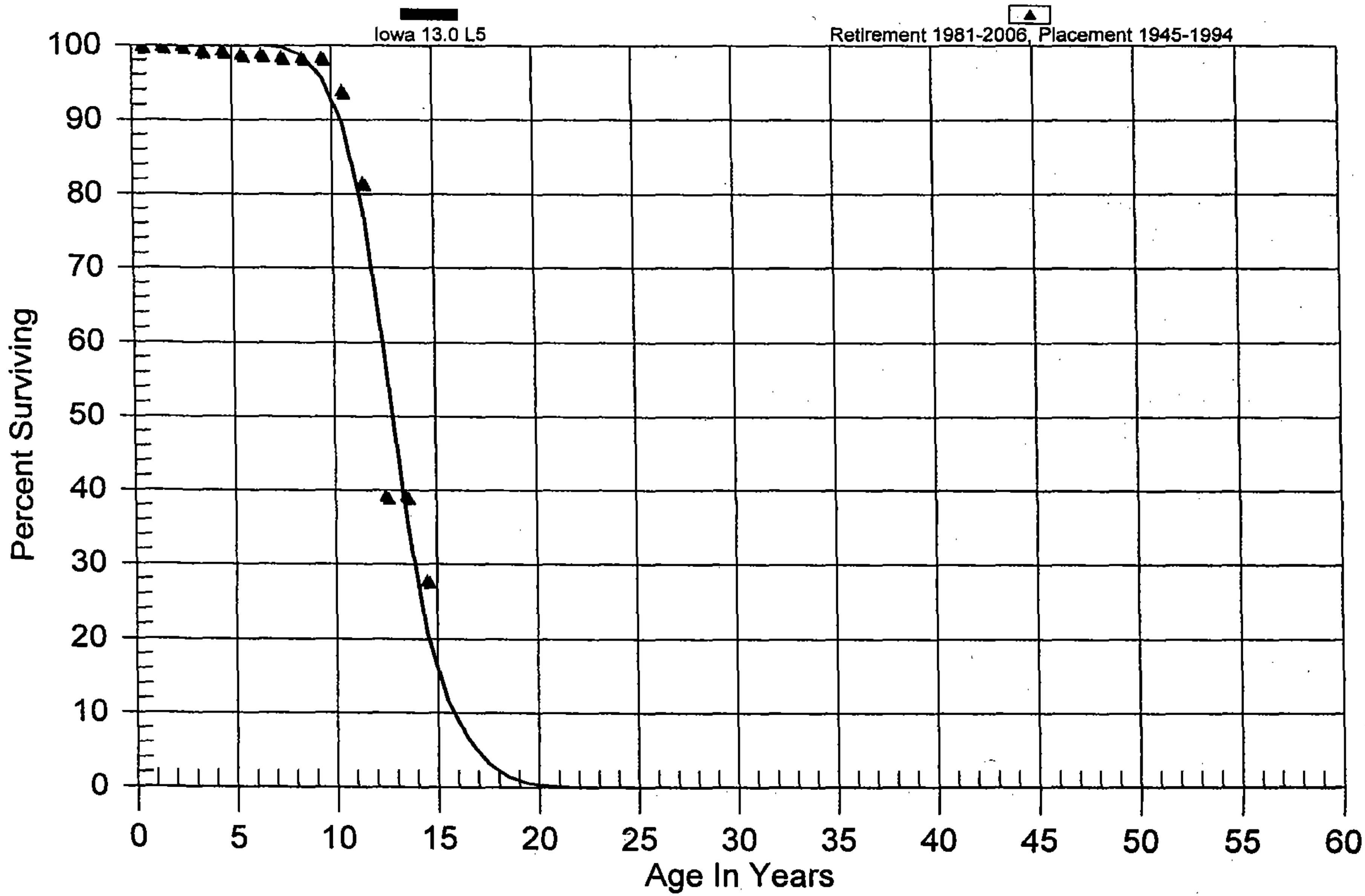
Northern Utilities, Inc.
New Hampshire
392.00 TRANSPORTATION EQUIPMENT

Observed Life Table
Retirement Expr. 1981 TO 2006
Placement Years 1972 TO 2001

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$691,364.20	$0.00	0.00000	100.00
0.5 - 1.5	$762,439.20	$0.00	0.00000	100.00
1.5 - 2.5	$780,504.20	$4,990.00	0.00639	100.00
2.5 - 3.5	$724,849.20	$32,378.55	0.04467	99.36
3.5 - 4.5	$694,018.65	$5,000.00	0.00720	94.92
4.5 - 5.5	$691,995.65	$5,850.00	0.00845	94.24
5.5 - 6.5	$686,838.65	$3,457.00	0.00503	93.44
6.5 - 7.5	$684,166.65	$58,464.46	0.08545	92.97
7.5 - 8.5	$623,866.28	$22,273.91	0.03570	85.03
8.5 - 9.5	$598,424.50	$48,030.64	0.08026	81.99
9.5 - 10.5	$550,393.86	$500,374.68	0.90912	75.41
10.5 - 11.5	$45,013.29	$7,745.00	0.17206	6.85
11.5 - 12.5	$9,789.00	$7,708.00	0.78741	5.67
12.5 - 13.5	$2,081.00	$1,777.00	0.85392	1.21
13.5 - 14.5	$304.00	$101.00	0.33224	0.18

Northern Utilities, Inc.

New Hampshire
393.00 STORES EQUIPMENT
Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
393.00 STORES EQUIPMENT

Observed Life Table
Retirement Expr. 1981 TO 2006
Placement Years 1945 TO 1994

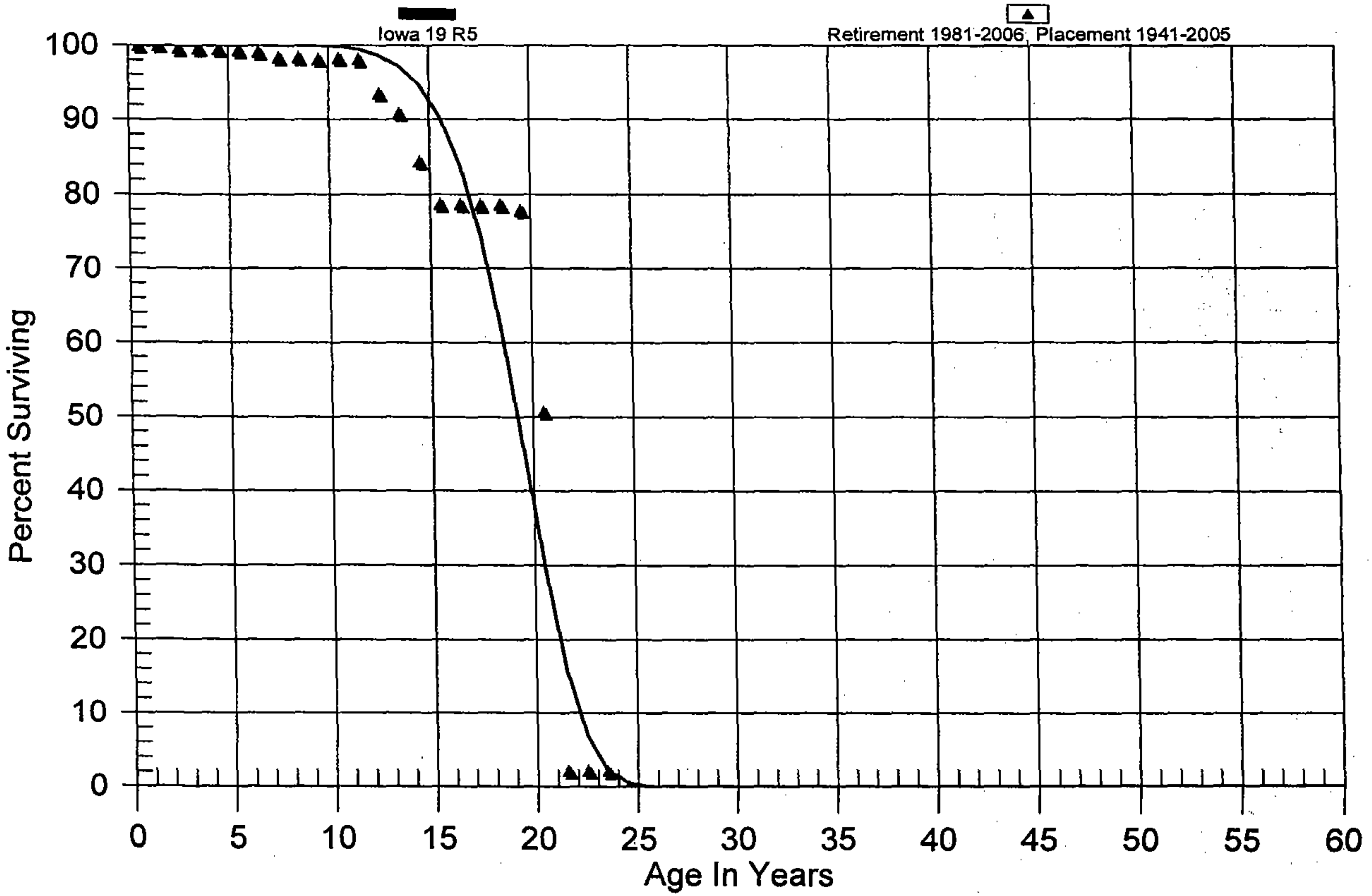
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$73,075.13	$0.00	0.00000	100.00
0.5 - 1.5	$73,075.13	$0.00	0.00000	100.00
1.5 - 2.5	$73,075.13	$0.00	0.00000	100.00
2.5 - 3.5	$73,075.13	$450.00	0.00616	100.00
3.5 - 4.5	$87,250.13	$0.00	0.00000	99.38
4.5 - 5.5	$87,250.13	$498.00	0.00571	99.38
5.5 - 6.5	$86,752.13	$0.00	0.00000	98.82
6.5 - 7.5	$86,752.13	$343.00	0.00395	98.82
7.5 - 8.5	$89,981.13	$0.00	0.00000	98.43
8.5 - 9.5	$89,981.13	$0.00	0.00000	98.43
9.5 - 10.5	$89,981.13	$4,224.72	0.04695	98.43
10.5 - 11.5	$85,756.41	$11,103.05	0.12947	93.81
11.5 - 12.5	$74,653.36	$38,765.31	0.51927	81.66
12.5 - 13.5	$15,088.05	$0.00	0.00000	39.26
13.5 - 14.5	$15,088.05	$4,368.10	0.28951	39.26

Northern Utilities, Inc.

New Hampshire

394.10 (387.00) TOOLS, GARAGE AND SERVICE EQ

Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
394.10 (387.00) TOOLS, GARAGE AND SERVICE EQ

Observed Life Table
Retirement Expr. 1981 TO 2006
Placement Years 1941 TO 2005

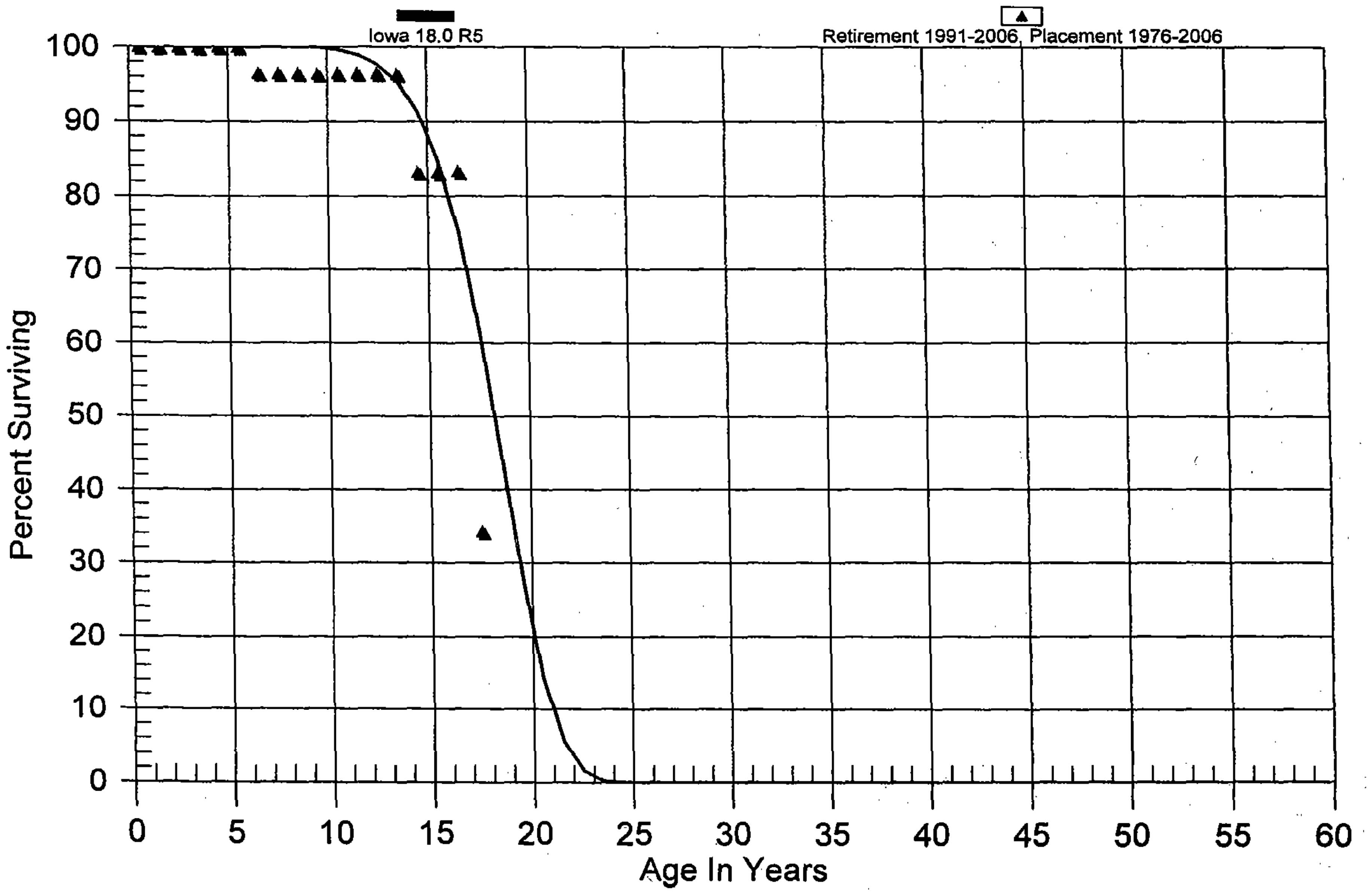
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$496,758.64	$0.00	0.00000	100.00
0.5 - 1.5	$509,832.87	$0.00	0.00000	100.00
1.5 - 2.5	$505,070.44	$2,176.38	0.00431	100.00
2.5 - 3.5	$484,381.82	$0.00	0.00000	99.57
3.5 - 4.5	$468,895.61	$441.01	0.00094	99.57
4.5 - 5.5	$466,704.41	$613.10	0.00131	99.48
5.5 - 6.5	$451,385.82	$995.66	0.00221	99.34
6.5 - 7.5	$432,453.86	$3,644.89	0.00843	99.13
7.5 - 8.5	$378,742.18	$146.59	0.00039	98.29
8.5 - 9.5	$355,880.81	$403.55	0.00113	98.25
9.5 - 10.5	$334,049.06	$3.11	0.00001	98.14
10.5 - 11.5	$305,589.94	$466.35	0.00153	98.14
11.5 - 12.5	$261,586.22	$12,414.07	0.04746	97.99
12.5 - 13.5	$237,048.16	$6,310.17	0.02662	93.34
13.5 - 14.5	$223,237.52	$15,778.58	0.07068	90.86
14.5 - 15.5	$175,117.11	$12,017.16	0.06862	84.43
15.5 - 16.5	$138,099.81	$0.00	0.00000	78.64
16.5 - 17.5	$113,746.30	$0.00	0.00000	78.64
17.5 - 18.5	$92,756.11	$36.22	0.00039	78.64
18.5 - 19.5	$60,747.60	$510.86	0.00841	78.61
19.5 - 20.5	$39,915.73	$13,948.64	0.34945	77.95
20.5 - 21.5	$16,022.49	$15,338.81	0.95733	50.71
21.5 - 22.5	$683.68	$0.00	0.00000	2.16
22.5 - 23.5	$683.68	$5.91	0.00864	2.16
23.5 - 24.5	$677.77	$667.82	0.98532	2.15

Northern Utilities, Inc.

New Hampshire

394.30 (394.00) TOOLS, TOOLS AND OTHER

Original And Smooth Survivor Curves



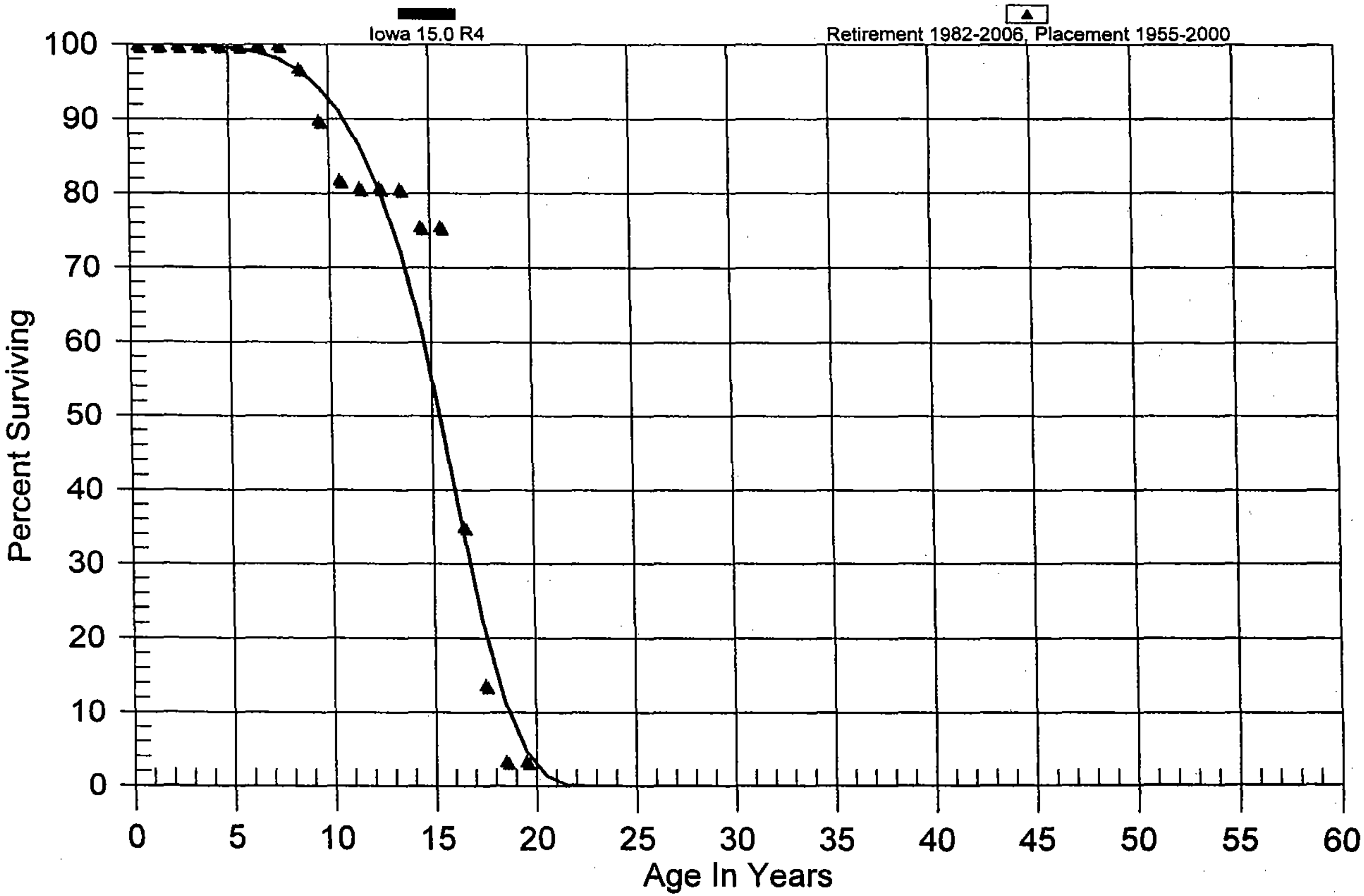
Northern Utilities, Inc.
New Hampshire
394.30 (394.00) TOOLS, TOOLS AND OTHER

Observed Life Table
Retirement Expr. 1991 TO 2006
Placement Years 1976 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$86,936.57	$0.00	0.00000	100.00
0.5 - 1.5	$57,586.57	$0.00	0.00000	100.00
1.5 - 2.5	$55,045.47	$0.00	0.00000	100.00
2.5 - 3.5	$37,555.27	$0.00	0.00000	100.00
3.5 - 4.5	$37,555.27	$0.00	0.00000	100.00
4.5 - 5.5	$41,377.14	$0.00	0.00000	100.00
5.5 - 6.5	$37,908.49	$1,387.17	0.03659	100.00
6.5 - 7.5	$32,145.71	$0.00	0.00000	96.34
7.5 - 8.5	$32,145.71	$0.00	0.00000	96.34
8.5 - 9.5	$29,320.71	$0.00	0.00000	96.34
9.5 - 10.5	$29,320.71	$0.00	0.00000	96.34
10.5 - 11.5	$29,070.71	$0.00	0.00000	96.34
11.5 - 12.5	$16,484.95	$0.00	0.00000	96.34
12.5 - 13.5	$7,921.77	$0.00	0.00000	96.34
13.5 - 14.5	$7,317.37	$995.00	0.13598	96.34
14.5 - 15.5	$9,322.37	$0.00	0.00000	83.24
15.5 - 16.5	$7,300.00	$0.00	0.00000	83.24
16.5 - 17.5	$7,300.00	$4,300.00	0.58904	83.24

Northern Utilities, Inc.

New Hampshire
396.00 POWER OPERATED EQUIPMENT
Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
396.00 POWER OPERATED EQUIPMENT

Observed Life Table
Retirement Expr. 1982 TO 2006
Placement Years 1955 TO 2000

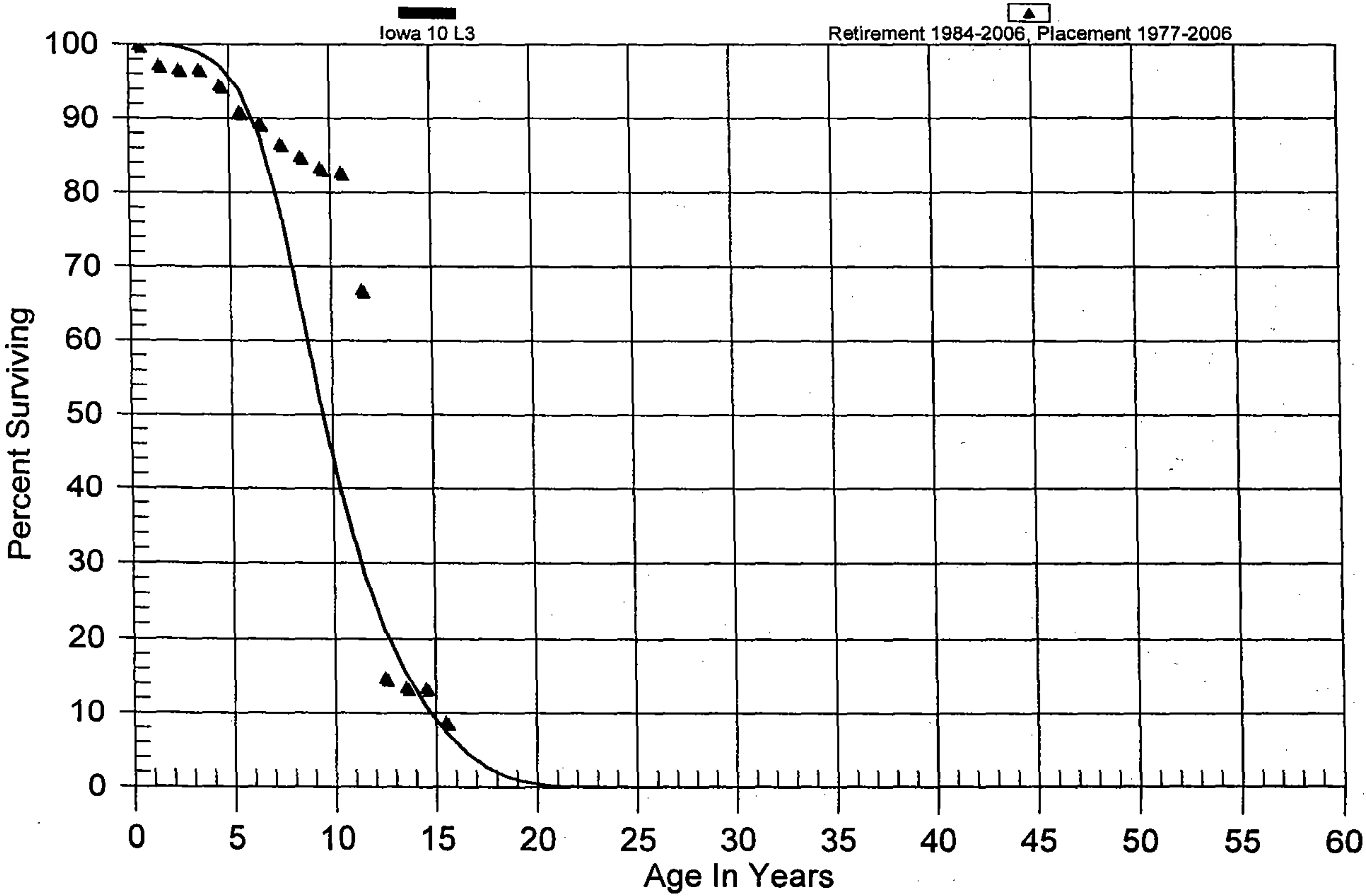
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$203,508.89	$0.00	0.00000	100.00
0.5 - 1.5	$196,458.89	$0.00	0.00000	100.00
1.5 - 2.5	$150,628.59	$0.00	0.00000	100.00
2.5 - 3.5	$247,880.74	$0.00	0.00000	100.00
3.5 - 4.5	$270,102.10	$0.00	0.00000	100.00
4.5 - 5.5	$308,690.10	$0.00	0.00000	100.00
5.5 - 6.5	$285,892.10	$0.00	0.00000	100.00
6.5 - 7.5	$290,205.11	$0.00	0.00000	100.00
7.5 - 8.5	$293,418.91	$9,205.00	0.03137	100.00
8.5 - 9.5	$291,263.91	$20,743.00	0.07122	96.86
9.5 - 10.5	$254,923.91	$22,991.00	0.09019	89.96
10.5 - 11.5	$263,127.91	$3,432.00	0.01304	81.85
11.5 - 12.5	$259,695.91	$0.00	0.00000	80.78
12.5 - 13.5	$259,695.91	$550.00	0.00212	80.78
13.5 - 14.5	$249,045.91	$15,598.00	0.06263	80.61
14.5 - 15.5	$233,447.91	$0.00	0.00000	75.56
15.5 - 16.5	$233,447.91	$125,242.40	0.53649	75.56
16.5 - 17.5	$55,723.01	$33,938.85	0.60906	35.02
17.5 - 18.5	$21,784.16	$16,281.36	0.74739	13.69
18.5 - 19.5	$5,502.80	$0.00	0.00000	3.46

Northern Utilities, Inc.

New Hampshire

397.00 COMMUNICATION EQUIPMENT

Original And Smooth Survivor Curves



Northern Utilities, Inc.
New Hampshire
397.00 COMMUNICATION EQUIPMENT
Observed Life Table
Retirement Expr. 1984 TO 2006
Placement Years 1977 TO 2006

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$887,083.26	$0.00	0.00000	100.00
0.5 - 1.5	$866,681.31	$24,754.79	0.02856	100.00
1.5 - 2.5	$800,741.87	$3,794.00	0.00474	97.14
2.5 - 3.5	$782,420.26	$902.00	0.00115	96.68
3.5 - 4.5	$763,793.71	$15,964.12	0.02090	96.57
4.5 - 5.5	$752,147.81	$28,028.02	0.03726	94.55
5.5 - 6.5	$715,244.49	$12,877.16	0.01800	91.03
6.5 - 7.5	$702,674.33	$22,468.58	0.03198	89.39
7.5 - 8.5	$646,965.33	$12,992.51	0.02008	86.53
8.5 - 9.5	$633,972.82	$10,728.52	0.01692	84.80
9.5 - 10.5	$587,084.01	$5,284.76	0.00900	83.36
10.5 - 11.5	$573,401.75	$109,569.95	0.19109	82.61
11.5 - 12.5	$427,810.11	$333,938.13	0.78058	66.82
12.5 - 13.5	$76,492.98	$6,350.12	0.08302	14.66
13.5 - 14.5	$70,142.86	$0.00	0.00000	13.45
14.5 - 15.5	$4,362.17	$1,508.07	0.34572	13.45

Section 6

Northern Utilities, Inc.
New Hampshire
305.00 PRODUCTION PLANT STRUCTURES

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *-5 %*

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
(305-311) PORTSMOUTH (BARBERRY LANE)					
Interim Survivor Curve: None					
Probable Retirement Year:	*2007*				
1994	45,545.45	12.50	0.50	13.00	3,503.50
1995	19,413.76	11.50	0.50	12.00	1,617.81
1999	10,500.00	7.50	0.50	8.00	1,312.50
Total	75,459.21				6,433.81
(305) BARBERRY LANE (BUTLER BLDG & SITE WORK)					
Interim Survivor Curve: None					
Probable Retirement Year:	*2036*				
1996	2,674.39	10.50	29.50	40.00	66.86
1997	560.00	9.50	29.50	39.00	14.36
1998	2,274.45	8.50	29.50	38.00	59.85
Total	5,508.84				141.07
Account Total	80,968.05				6,574.88

Annual Accural Rate ... 8.53 %

Northern Utilities, Inc.
New Hampshire
311.00 OTHER GAS GENERATING EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -10 %

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
		(305-311) PORTSMOUTH (BARBERRY LANE)			
Interim Survivor Curve: None					
Probable Retirement Year:	*2007*				
1967	29,291.90	39.50	0.50	40.00	732.30
1968	4,709.02	38.50	0.50	39.00	120.74
1970	2,399.49	36.50	0.50	37.00	64.85
1972	4,370.00	34.50	0.50	35.00	124.86
1975	425.87	31.50	0.50	32.00	13.31
1981	150,358.70	25.50	0.50	26.00	5,783.03
1982	147,778.23	24.50	0.50	25.00	5,911.13
1983	1,205.82	23.50	0.50	24.00	50.24
1992	746.40	14.50	0.50	15.00	49.76
1993	991.31	13.50	0.50	14.00	70.81
1994	21,784.54	12.50	0.50	13.00	1,675.73
1996	1,333.00	10.50	0.50	11.00	121.18
1998	8,467.45	8.50	0.50	9.00	940.83
Total	373,861.73				15,658.77
Account Total	373,861.73				15,658.77

Annual Accural Rate ... 4.61 %

Northern Utilities, Inc.
New Hampshire
320.00 OTHER PRODUCTION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 20 Survivor Curve: R4

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1990	590.00	15.93	4.07	20.00	29.50
1993	6,416.03	13.31	6.69	20.00	320.80
1998	634.13	8.48	11.52	20.00	31.71
Total	7,640.16				382.01

Annual Accural Rate ... 5.0 %

Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 20 Survivor Curve: R5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1974	19,596.83	0.00	0.00	20.00	979.84
1993	31,847.78	13.48	6.52	20.00	1,592.39
1994	5,416.15	12.49	7.51	20.00	270.81
Total	56,860.76				2,843.04

Annual Accural Rate ... *5.0 %*

Northern Utilities, Inc.
New Hampshire
374.40 LAND RIGHTS-OTHER DISTR SYSTEM
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 70 Survivor Curve: R4

Year	*Original Cost*	*Realized Life*	*Expectancy*	*Avg. Service Life*	*Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
2005	297.50	1.50	68.50	70.00	4.25
Total	297.50				4.25

Annual Accural Rate ... *1.4 %*

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 %

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
		(375.2) DOVER (COCHECO STREET)			
Interim Survivor Curve: Iowa		*80 L0*			
Probable Retirement Year:		*2016*			
1957	2,579.00	42.37	6.05	48.42	53.26
1978	1,906.00	26.51	7.60	34.11	55.88
Total	4,485.00				109.14
		(375.2) EXETER (WATER STREET)			
Interim Survivor Curve: Iowa		*80 L0*			
Probable Retirement Year:		*2014*			
1974	400.00	0.00	0.00	80.00	5.00
Total	400.00				5.00
		(375.2) PORTSMOUTH (GOVERNOR HOUSE - INSINGTO)			
Interim Survivor Curve: Iowa		*80 L0*			
Probable Retirement Year:		*2016*			
1939	646.00	0.00	0.00	80.00	8.08
1956	2,332.00	0.00	0.00	80.00	29.15
Total	2,978.00				37.23
		(375.2) SOMERSWORTH			
Interim Survivor Curve: Iowa		*80 L0*			
Probable Retirement Year:		*2016*			
1978	867.00	0.00	0.00	80.00	10.84

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 %

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
Total	867.00				10.84

(375.2) PORTSMOUTH

Interim Survivor Curve: Iowa 80 L0
Probable Retirement Year: 2046

2006	39,465.14	0.00	0.00	80.00	493.31
Total	39,465.14				493.31
Account Total	48,195.14				655.52

Annual Accural Rate ... 1.43 %

Northern Utilities, Inc.

New Hampshire

375.70 (390.00) OTHER DISTRIBUTION SYSTEM STRUCT.

Original Cost Of Utility Plant In Service

And Development Of Annual Depr Rate as of December 31, 2006

Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 %

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
			(375.7) PORTSMOUTH		
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2033					
1988	1,883,351.00	0.00	0.00	80.00	23,541.89
1989	39,541.00	0.00	0.00	80.00	494.26
1990	38,589.00	0.00	0.00	80.00	482.36
1992	9,564.07	0.00	0.00	80.00	119.55
1993	67,044.70	0.00	0.00	80.00	838.06
1994	13,163.86	0.00	0.00	80.00	164.55
1995	8,284.75	0.00	0.00	80.00	103.56
1996	71,609.37	0.00	0.00	80.00	895.12
1997	31,263.62	0.00	0.00	80.00	390.80
1998	60,287.23	0.00	0.00	80.00	753.59
1999	2,300.00	0.00	0.00	80.00	28.75
2001	2,160.50	0.00	0.00	80.00	27.01
2002	15,061.71	0.00	0.00	80.00	188.27
2004	44,717.46	0.00	0.00	80.00	558.97
Total	2,286,938.27				28,586.73
Account Total	2,286,938.27				28,586.73

Annual Accural Rate ... 1.25 %

Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: R3

Year (1)	*Original Cost* (2)	*Realized Life* (3)	*Expectancy* (4)	*Avg. Service Life* (5)	*Annual Accruals* (6)
1966	140,092.68	37.26	7.74	45.00	3,113.17
1967	101,495.56	36.57	8.43	45.00	2,255.46
1968	82,762.91	35.85	9.15	45.00	1,839.18
1969	42,463.72	35.12	9.88	45.00	943.64
1970	112,924.74	34.36	10.64	45.00	2,509.44
1971	45,958.40	33.58	11.42	45.00	1,021.30
1972	90,986.98	32.78	12.22	45.00	2,021.93
1973	118,589.99	31.96	13.04	45.00	2,635.33
1974	113,763.78	31.13	13.87	45.00	2,528.08
1975	89,032.13	30.28	14.72	45.00	1,978.49
1976	110,744.26	29.42	15.58	45.00	2,460.98
1977	70,172.30	28.54	16.46	45.00	1,559.38
1978	170,093.56	27.66	17.34	45.00	3,779.86
1979	485,519.17	26.76	18.24	45.00	10,789.31
1980	55,044.05	25.85	19.15	45.00	1,223.20
1981	85,242.07	24.93	20.07	45.00	1,894.27
1982	165,308.61	24.01	20.99	45.00	3,673.52
1983	55,460.59	23.07	21.93	45.00	1,232.46
1984	263,076.83	22.13	22.87	45.00	5,846.15
1985	510,555.66	21.18	23.82	45.00	11,345.68
1986	288,416.28	20.23	24.77	45.00	6,409.25
1987	132,268.64	19.27	25.73	45.00	2,939.30
1988	189,300.18	18.31	26.69	45.00	4,206.67
1989	342,093.61	17.34	27.66	45.00	7,602.08
1990	874,841.15	16.37	28.63	45.00	19,440.91
1991	1,060,516.85	15.39	29.61	45.00	23,567.04

Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1992	194,698.61	14.41	30.59	45.00	4,326.64
1993	96,355.14	13.43	31.57	45.00	2,141.23
1994	79,089.11	12.44	32.56	45.00	1,757.54
1995	2,045,335.50	11.45	33.55	45.00	45,451.90
1996	2,802,310.83	10.46	34.54	45.00	62,273.57
1997	1,123,969.00	9.47	35.53	45.00	24,977.09
1998	237,984.69	8.48	36.52	45.00	5,288.55
1999	270,358.39	7.48	37.52	45.00	6,007.96
2000	426,870.64	6.49	38.51	45.00	9,486.01
2001	231,494.17	5.49	39.51	45.00	5,144.31
2002	795,988.45	4.50	40.50	45.00	17,688.63
2003	309,162.79	3.50	41.50	45.00	6,870.28
2004	126,744.67	2.50	42.50	45.00	2,816.55
2005	165,062.33	1.50	43.50	45.00	3,668.05
2006	469,402.62	0.50	44.50	45.00	10,431.17
Total	15,171,551.64				337,145.59

Annual Accural Rate ... *2.8 %*

Northern Utilities, Inc.
New Hampshire
376.30 (367.60) MAINS - STEEL MAINS (BARE)
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 31 Survivor Curve: L3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1928	4,700.13	0.00	0.00	31.00	151.62
1939	5,606.76	0.00	0.00	31.00	180.86
1940	2,130.74	0.00	0.00	31.00	68.73
1941	10,581.98	0.00	0.00	31.00	341.35
1945	1,864.64	30.99	0.01	31.00	60.15
1949	396.19	30.96	0.04	31.00	12.78
1950	2,928.75	30.94	0.06	31.00	94.48
1953	6,912.42	30.87	0.13	31.00	222.98
1954	8,193.65	30.84	0.16	31.00	264.31
1955	18,212.50	30.80	0.20	31.00	587.50
1956	24,138.25	30.75	0.25	31.00	778.65
1957	10,973.41	30.70	0.30	31.00	353.98
1958	8,212.92	30.63	0.37	31.00	264.93
1959	14,280.35	30.56	0.44	31.00	460.66
1960	7,580.56	30.47	0.53	31.00	244.53
1961	41,353.10	30.38	0.62	31.00	1,333.97
1962	53,666.74	30.27	0.73	31.00	1,731.19
1963	109,600.96	30.14	0.85	31.00	3,535.51
1964	52,567.84	30.01	0.99	31.00	1,695.74
1965	15,874.03	29.85	1.14	31.00	512.07
2006	10,464.49	0.50	30.50	31.00	337.56
Total	410,240.41				13,233.56

Annual Accural Rate ... 4.0 %

Northern Utilities, Inc.
New Hampshire
376.40 (367.70) MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: S2

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1974	2,090.57	31.07	13.93	45.00	46.46
1975	20,303.65	30.26	14.74	45.00	451.19
1976	45,911.41	29.43	15.57	45.00	1,020.25
1977	54,526.52	28.59	16.41	45.00	1,211.70
1978	40,482.33	27.72	17.28	45.00	899.61
1979	149,554.26	26.84	18.16	45.00	3,323.43
1980	171,865.51	25.95	19.05	45.00	3,819.23
1981	254,041.77	25.04	19.96	45.00	5,645.37
1982	89,847.08	24.12	20.88	45.00	1,996.60
1983	143,815.99	23.19	21.81	45.00	3,195.91
1984	216,531.46	22.25	22.75	45.00	4,811.81
1985	553,824.64	21.30	23.70	45.00	12,307.21
1986	565,332.96	20.34	24.66	45.00	12,562.95
1987	1,148,683.01	19.38	25.62	45.00	25,526.29
1988	1,187,575.44	18.41	26.59	45.00	26,390.57
1989	1,084,305.27	17.43	27.57	45.00	24,095.67
1990	2,019,092.23	16.45	28.55	45.00	44,868.72
1991	3,137,812.86	15.46	29.54	45.00	69,729.17
1992	2,423,782.75	14.47	30.53	45.00	53,861.84
1993	1,749,844.14	13.48	31.52	45.00	38,885.43
1994	2,560,031.50	12.49	32.51	45.00	56,889.59
1995	1,684,276.30	11.49	33.51	45.00	37,428.36
1996	1,264,969.36	10.50	34.50	45.00	28,110.43
1997	1,562,482.52	9.50	35.50	45.00	34,721.83
1998	1,412,019.85	8.50	36.50	45.00	31,378.22
1999	2,000,341.44	7.50	37.50	45.00	44,452.03

Northern Utilities, Inc.
New Hampshire
376.40 (367.70) MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: S2

Year (1)	*Original Cost* (2)	*Realized Life* (3)	*Expectancy* (4)	*Avg. Service Life* (5)	*Annual Accruals* (6)
2000	1,487,746.34	6.50	38.50	45.00	33,061.03
2001	1,573,940.09	5.50	39.50	45.00	34,976.45
2002	773,229.24	4.50	40.50	45.00	17,182.87
2003	1,228,221.40	3.50	41.50	45.00	27,293.81
2004	2,054,811.99	2.50	42.50	45.00	45,662.49
2005	2,553,990.23	1.50	43.50	45.00	56,755.34
2006	2,698,407.07	0.50	44.50	45.00	59,964.60
Total	37,913,691.18				842,526.47

Annual Accural Rate ... 2.8 %

Northern Utilities, Inc.
New Hampshire
376.50 (367.20) MAINS - JOINT CLAMPS

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 16 Survivor Curve: L5

Year	*Original Cost*	*Realized Life*	*Expectancy*	*Avg. Service Life*	*Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1990	123,685.78	15.20	0.80	16.00	7,730.36
1991	136,401.15	14.73	1.27	16.00	8,525.07
1992	33,444.56	14.08	1.92	16.00	2,090.29
1993	85,586.12	13.29	2.71	16.00	5,349.13
1994	52,782.68	12.41	3.59	16.00	3,298.92
1995	37,918.25	11.46	4.54	16.00	2,369.89
1996	64,403.32	10.49	5.51	16.00	4,025.21
1997	88,020.77	9.50	6.50	16.00	5,501.30
1998	34,253.81	8.50	7.50	16.00	2,140.86
1999	9,540.21	7.50	8.50	16.00	596.26
2000	18,974.49	6.50	9.50	16.00	1,185.91
2001	11,620.08	5.50	10.50	16.00	726.26
2002	7,277.39	4.50	11.50	16.00	454.84
2003	15,547.56	3.50	12.50	16.00	971.72
2004	37,630.61	2.50	13.50	16.00	2,351.91
2005	44,996.89	1.50	14.50	16.00	2,812.31
2006	17,876.00	0.50	15.50	16.00	1,117.25
Total	819,959.67				51,247.48

Annual Accural Rate ... *7.8 %*

Northern Utilities, Inc.
New Hampshire
376.60 (367.50) MAINS - CATHODIC PROTECTION
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 18 Survivor Curve: R5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1991	1,069.53	15.26	2.74	18.00	59.42
1992	17,059.36	14.37	3.63	18.00	947.74
1993	17,144.61	13.44	4.56	18.00	952.48
1994	16,227.44	12.47	5.53	18.00	901.52
1995	23,991.12	11.49	6.51	18.00	1,332.84
1996	10,252.03	10.50	7.50	18.00	569.56
1997	11,779.22	9.50	8.50	18.00	654.40
1998	58,435.79	8.50	9.50	18.00	3,246.43
1999	29,488.21	7.50	10.50	18.00	1,638.23
2000	5,383.56	6.50	11.50	18.00	299.09
2001	2,582.15	5.50	12.50	18.00	143.45
2002	10,631.12	4.50	13.50	18.00	590.62
2003	30,482.95	3.50	14.50	18.00	1,693.50
2004	31,744.74	2.50	15.50	18.00	1,763.60
2005	17,549.14	1.50	16.50	18.00	974.95
2006	24,946.29	0.50	17.50	18.00	1,385.91
Total	308,767.26				17,153.74

Annual Accural Rate ... 6.9 %

Northern Utilities, Inc.
New Hampshire
376.80 (367.10) MAINS - CAST IRON

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 62 Survivor Curve: S5

Year	*Original Cost*	*Realized Life*	*Expectancy*	*Avg. Service Life*	*Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1939	44,883.68	61.03	0.97	62.00	723.93
1941	31,933.64	60.49	1.51	62.00	515.06
1945	3,762.08	58.80	3.20	62.00	60.68
1953	5,448.72	53.06	8.94	62.00	87.88
2003	1,685.27	3.50	58.50	62.00	27.18
Total	87,713.39				1,414.73

Annual Accural Rate ... 2.0 %

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 % Average Service Life: 30 Survivor Curve: R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1956	3,711.71	0.00	0.00	30.00	123.72
1970	3,806.03	29.18	0.82	30.00	126.87
1971	1,106.53	28.93	1.07	30.00	36.88
1973	2,969.09	28.29	1.71	30.00	98.97
1974	9,065.61	27.90	2.10	30.00	302.19
1978	11,927.96	25.81	4.19	30.00	397.60
1979	25,491.70	25.17	4.83	30.00	849.72
1980	5,454.31	24.49	5.51	30.00	181.81
1981	1,655.91	23.78	6.22	30.00	55.20
1985	17,703.88	20.61	9.39	30.00	590.13
1986	26,442.33	19.76	10.24	30.00	881.41
1988	20,534.24	17.99	12.01	30.00	684.47
1989	30,889.02	17.08	12.92	30.00	1,029.63
1990	122,239.45	16.16	13.84	30.00	4,074.65
1991	99,745.76	15.23	14.77	30.00	3,324.86
1992	38,665.95	14.28	15.72	30.00	1,288.87
1993	47,418.82	13.33	16.67	30.00	1,580.63
1994	112,232.69	12.37	17.63	30.00	3,741.09
1995	116,805.19	11.40	18.60	30.00	3,893.51
1996	193,131.71	10.42	19.58	30.00	6,437.72
1997	147,291.23	9.44	20.56	30.00	4,909.71
1998	110,779.24	8.46	21.54	30.00	3,692.64
1999	174,530.40	7.47	22.53	30.00	5,817.68
2000	257,845.24	6.48	23.52	30.00	8,594.84
2001	50,602.99	5.49	24.51	30.00	1,686.77
2002	15,958.64	4.49	25.51	30.00	531.95

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 % Average Service Life: 30 Survivor Curve: R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
2003	90,791.33	3.50	26.50	30.00	3,026.38
2004	124,267.03	2.50	27.50	30.00	4,142.23
2005	90,181.40	1.50	28.50	30.00	3,006.05
Total	1,953,245.39				65,108.18

Annual Accural Rate ... 3.5 %

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -90 % Average Service Life: 47 Survivor Curve: R3

Year (1)	*Original Cost* (2)	*Realized Life* (3)	*Expectancy* (4)	*Avg. Service Life* (5)	*Annual Accruals* (6)
1934	82.71	46.99	0.01	47.00	1.76
1939	235.82	46.90	0.10	47.00	5.02
1940	22.32	46.85	0.15	47.00	0.47
1944	209.14	46.57	0.43	47.00	4.45
1945	449.18	46.46	0.54	47.00	9.56
1946	166.67	46.33	0.67	47.00	3.55
1947	1,279.67	46.17	0.83	47.00	27.23
1948	1,242.05	45.99	1.01	47.00	26.43
1949	940.92	45.79	1.21	47.00	20.02
1951	237.14	45.30	1.70	47.00	5.05
1952	1,000.62	45.01	1.99	47.00	21.29
1953	2,629.39	44.69	2.31	47.00	55.94
1954	1,279.65	44.34	2.66	47.00	27.23
1955	1,194.97	43.95	3.05	47.00	25.42
1956	3,198.67	43.53	3.47	47.00	68.06
1957	9,973.06	43.08	3.92	47.00	212.19
1958	7,951.87	42.59	4.41	47.00	169.19
1959	8,345.68	42.08	4.92	47.00	177.57
1960	7,224.12	41.53	5.47	47.00	153.70
1961	14,677.44	40.95	6.05	47.00	312.29
1962	23,628.48	40.35	6.65	47.00	502.73
1963	16,545.16	39.71	7.29	47.00	352.02
1964	29,974.11	39.05	7.95	47.00	637.75
1965	23,195.94	38.37	8.63	47.00	493.53
1966	21,044.96	37.66	9.34	47.00	447.77
1967	27,917.62	36.92	10.08	47.00	593.99

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -90 %   Average Service Life: 47   Survivor Curve: R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
Total	204,647.36				4,354.20

Annual Accural Rate ...   4.0 %

Northern Utilities, Inc.
New Hampshire
380.20 SERVICES - COATED STEEL NOT WRAPPED
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -90 %   Average Service Life: 38   Survivor Curve: L3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1968	15,732.31	33.21	4.79	38.00	414.01
1969	6,769.19	32.78	5.22	38.00	178.14
1970	8,802.96	32.30	5.69	38.00	231.66
1971	20,161.77	31.80	6.20	38.00	530.57
1972	34,970.27	31.26	6.74	38.00	920.27
1973	39,169.64	30.68	7.32	38.00	1,030.78
1974	54,640.18	30.07	7.93	38.00	1,437.90
1975	30,770.53	29.42	8.58	38.00	809.75
1976	42,873.29	28.73	9.27	38.00	1,128.24
Total	253,890.14				6,681.32

Annual Accural Rate ...   *5.0 %*

Northern Utilities, Inc.
New Hampshire
380.30 SERVICES - STEEL COATED & WRAPPED

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -90 %   Average Service Life: 38   Survivor Curve: R1.5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1977	9,335.25	26.15	11.85	38.00	245.66
1978	11,169.74	25.43	12.57	38.00	293.94
1979	54,754.30	24.69	13.31	38.00	1,440.90
1980	13,755.97	23.94	14.06	38.00	362.00
1981	30,132.08	23.17	14.83	38.00	792.95
1982	22,976.16	22.39	15.61	38.00	604.64
Total	142,123.50				3,740.09

Annual Accural Rate ...   5.0 %

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -90 % Average Service Life: 40 Survivor Curve: R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1970	3,966.00	33.46	6.54	40.00	99.15
1971	11,065.43	32.78	7.22	40.00	276.64
1972	12,918.44	32.07	7.93	40.00	322.96
1973	13,966.36	31.34	8.66	40.00	349.16
1974	21,594.66	30.58	9.42	40.00	539.87
1975	14,346.70	29.80	10.20	40.00	358.67
1976	14,112.13	29.00	11.00	40.00	352.80
1977	70,348.78	28.18	11.82	40.00	1,758.72
1978	71,624.86	27.34	12.66	40.00	1,790.62
1979	319,202.09	26.49	13.51	40.00	7,980.05
1980	141,044.76	25.62	14.38	40.00	3,526.12
1981	178,978.26	24.73	15.27	40.00	4,474.46
1982	149,474.60	23.84	16.16	40.00	3,736.87
1983	142,428.17	22.93	17.07	40.00	3,560.70
1984	187,877.35	22.01	17.99	40.00	4,696.93
1985	341,211.93	21.08	18.92	40.00	8,530.30
1986	487,817.80	20.14	19.86	40.00	12,195.45
1987	665,352.52	19.20	20.80	40.00	16,633.81
1988	818,982.94	18.25	21.75	40.00	20,474.57
1989	822,528.43	17.29	22.71	40.00	20,563.21
1990	1,373,114.41	16.33	23.67	40.00	34,327.86
1991	1,331,985.80	15.36	24.64	40.00	33,299.65
1992	1,157,850.49	14.38	25.62	40.00	28,946.26
1993	855,770.82	13.41	26.59	40.00	21,394.27
1994	1,831,662.53	12.43	27.57	40.00	45,791.56
1995	919,616.07	11.44	28.56	40.00	22,990.40

Northern Utilities, Inc.

New Hampshire

380.40 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service

And Development Of Annual Depr Rate as of December 31, 2006

Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -90 % Average Service Life: 40 Survivor Curve: R3

Year (1)	*Original Cost* (2)	*Realized Life* (3)	*Expectancy* (4)	*Avg. Service Life* (5)	*Annual Accruals* (6)
1996	1,139,530.59	10.46	29.54	40.00	28,488.26
1997	1,171,892.89	9.47	30.53	40.00	29,297.32
1998	1,082,154.35	8.47	31.53	40.00	27,053.86
1999	946,135.44	7.48	32.52	40.00	23,653.39
2000	936,245.47	6.49	33.51	40.00	23,406.14
2001	726,634.04	5.49	34.51	40.00	18,165.85
2002	1,137,613.32	4.49	35.51	40.00	28,440.33
2003	853,184.70	3.50	36.50	40.00	21,329.62
2004	1,017,037.72	2.50	37.50	40.00	25,425.94
2005	1,208,829.75	1.50	38.50	40.00	30,220.74
2006	1,139,416.28	0.50	39.50	40.00	28,485.41
Total	23,317,516.88				582,937.92

Annual Accural Rate ... *4.8 %*

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 30 Survivor Curve: R5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1975	19,604.20	29.08	0.92	30.00	653.47
1976	53,597.72	28.65	1.35	30.00	1,786.59
1977	90,768.28	28.12	1.88	30.00	3,025.61
1978	111,830.67	27.49	2.51	30.00	3,727.69
1979	146,035.82	26.77	3.23	30.00	4,867.86
1980	1,500.00	25.99	4.01	30.00	50.00
1981	267,176.76	25.15	4.85	30.00	8,905.89
1982	51,285.89	24.26	5.74	30.00	1,709.53
1983	50,588.50	23.34	6.66	30.00	1,686.28
1984	13,043.24	22.40	7.60	30.00	434.77
1985	96,499.57	21.44	8.56	30.00	3,216.65
1986	24,606.27	20.46	9.54	30.00	820.21
1987	76,664.32	19.48	10.52	30.00	2,555.48
1988	48,784.97	18.49	11.51	30.00	1,626.17
1989	94,748.62	17.50	12.50	30.00	3,158.29
1990	214,954.67	16.50	13.50	30.00	7,165.16
1991	193,803.31	15.50	14.50	30.00	6,460.11
1992	19,238.04	14.50	15.50	30.00	641.27
1993	30,733.71	13.50	16.50	30.00	1,024.46
1994	126,429.50	12.50	17.50	30.00	4,214.32
1995	84,769.61	11.50	18.50	30.00	2,825.65
1996	44,416.21	10.50	19.50	30.00	1,480.54
1997	136,809.65	9.50	20.50	30.00	4,560.32
1998	13,594.44	8.50	21.50	30.00	453.15
1999	64,015.52	7.50	22.50	30.00	2,133.85
2000	10,903.22	6.50	23.50	30.00	363.44

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 30 Survivor Curve: R5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
2001	34,537.54	5.50	24.50	30.00	1,151.25
2002	31,004.04	4.50	25.50	30.00	1,033.47
2003	44,940.50	3.50	26.50	30.00	1,498.02
2004	54,874.03	2.50	27.50	30.00	1,829.13
2005	180,263.73	1.50	28.50	30.00	6,008.79
Total	2,432,022.55				81,067.42

Annual Accural Rate ... *3.3 %*

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -10 % Average Service Life: 32 Survivor Curve: R4

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1975	11,847.40	29.12	2.88	32.00	370.23
1976	14,147.41	28.50	3.50	32.00	442.11
1977	14,353.71	27.84	4.16	32.00	448.55
1978	21,154.92	27.12	4.88	32.00	661.09
1979	52,090.16	26.37	5.63	32.00	1,627.82
1980	39,693.16	25.57	6.43	32.00	1,240.41
1981	45,691.70	24.75	7.25	32.00	1,427.87
1982	40,772.86	23.90	8.10	32.00	1,274.15
1983	34,439.17	23.02	8.98	32.00	1,076.22
1984	32,808.52	22.12	9.88	32.00	1,025.27
1985	49,790.75	21.20	10.80	32.00	1,555.96
1986	102,781.14	20.27	11.73	32.00	3,211.91
1987	113,561.02	19.32	12.68	32.00	3,548.78
1988	157,188.44	18.37	13.63	32.00	4,912.14
1989	241,895.26	17.40	14.60	32.00	7,559.23
1990	327,606.07	16.43	15.57	32.00	10,237.69
1991	340,875.43	15.45	16.55	32.00	10,652.36
1992	357,389.31	14.46	17.54	32.00	11,168.42
1993	366,563.52	13.47	18.53	32.00	11,455.11
1994	425,505.55	12.48	19.52	32.00	13,297.05
1995	359,183.25	11.49	20.51	32.00	11,224.48
1996	389,507.50	10.49	21.51	32.00	12,172.11
1997	454,996.44	9.49	22.51	32.00	14,218.64
1998	560,301.30	8.50	23.50	32.00	17,509.42
1999	568,345.43	7.50	24.50	32.00	17,760.79
2000	535,732.98	6.50	25.50	32.00	16,741.66

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -10 % Average Service Life: 32 Survivor Curve: R4

Year (1)	*Original Cost* (2)	*Realized Life* (3)	*Expectancy* (4)	*Avg. Service Life* (5)	*Annual Accruals* (6)
2001	471,499.12	5.50	26.50	32.00	14,734.35
2002	618,283.22	4.50	27.50	32.00	19,321.35
2003	553,688.30	3.50	28.50	32.00	17,302.76
2004	515,468.03	2.50	29.50	32.00	16,108.38
2005	1,309,619.49	1.50	30.50	32.00	40,925.61
2006	69,475.16	0.50	31.50	32.00	2,171.10
Total	9,196,255.72				287,382.99

Annual Accural Rate ... *3.4 %*

Northern Utilities, Inc.
New Hampshire
383.00 GAS REGULATORS

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % *Average Service Life:* 30 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1999	6,775.57	7.47	22.53	30.00	225.85
2000	3,744.90	6.48	23.52	30.00	124.83
2001	134,243.25	5.49	24.51	30.00	4,474.78
2002	350.30	4.49	25.51	30.00	11.68
2003	542.83	3.50	26.50	30.00	18.09
2004	39,538.37	2.50	27.50	30.00	1,317.95
Total	185,195.22				6,173.17

Annual Accural Rate ... 3.3 %

Northern Utilities, Inc.
New Hampshire
386.10 (386.00) MISC. PROP ON CUSTOMERS' PREM.

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 10 % Average Service Life: 10 Survivor Curve: R1.5

Year (1)	*Original Cost* (2)	*Realized Life* (3)	*Expectancy* (4)	*Avg. Service Life* (5)	*Annual Accruals* (6)
1994	45,359.73	9.33	0.68	10.00	4,535.97
1995	101,392.20	8.97	1.03	10.00	10,139.22
1996	76,158.18	8.53	1.47	10.00	7,615.82
1997	78,551.26	8.00	2.00	10.00	7,855.13
1998	76,451.16	7.38	2.62	10.00	7,645.12
1999	83,910.93	6.69	3.31	10.00	8,391.09
2000	123,831.03	5.93	4.07	10.00	12,383.10
2001	57,530.70	5.12	4.88	10.00	5,753.07
2002	92,107.97	4.26	5.74	10.00	9,210.80
2003	7,153.19	3.36	6.64	10.00	715.32
2004	8,867.40	2.44	7.57	10.00	886.74
2005	13,000.53	1.48	8.52	10.00	1,300.05
Total	764,314.28				76,431.43

Annual Accural Rate ... 9.0 %

Northern Utilities, Inc.
New Hampshire
391.10 (391.10) OFFICE FURN & EQ-UNSPECIFIED
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 2 % *Average Service Life:* 11 *Survivor Curve:* S3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1994	55,521.82	10.50	0.50	11.00	5,047.44
1995	287,709.13	10.13	0.87	11.00	26,155.38
1996	72,621.13	9.63	1.37	11.00	6,601.92
1997	26,919.23	9.00	2.00	11.00	2,447.20
1998	15,109.87	8.24	2.76	11.00	1,373.62
1999	30,754.11	7.38	3.62	11.00	2,795.83
2002	67,792.64	4.50	6.50	11.00	6,162.97
Total	556,427.93				50,584.36

Annual Accural Rate ... 8.9 %

Northern Utilities, Inc.
New Hampshire
391.11 (391.10 & 20) OFFICE FURN & EQ-DATA HANDLING EQ
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 10 Survivor Curve: R4

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
2004	7,565.50	2.50	7.50	10.00	756.55
Total	7,565.50				756.55

Annual Accural Rate ... 10.0 %

Northern Utilities, Inc.
New Hampshire
391.12 (391.30) INFORMATION SYSTEMS

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *0 %* *Average Service Life:* *8* *Survivor Curve:* *L4*

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
2002	17,724.71	4.48	3.52	8.00	2,215.59
2003	31,532.72	3.50	4.50	8.00	3,941.59
2004	5,250.00	2.50	5.50	8.00	656.25
2005	69,362.10	1.50	6.50	8.00	8,670.26
Total	123,869.53				15,483.69

Annual Accural Rate ... *12.5 %*

Northern Utilities, Inc.
New Hampshire
392.00 TRANSPORTATION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 10 % Average Service Life: 9 Survivor Curve: L4

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1995	27,479.29	8.83	0.17	9.00	3,053.25
1996	5,005.89	8.66	0.34	9.00	556.21
1999	2,290.91	7.23	1.77	9.00	254.55
2001	3,900.00	5.47	3.53	9.00	433.33
Total	38,676.09				4,297.34

Annual Accural Rate ... 10.0 %

Northern Utilities, Inc.
New Hampshire
393.00 STORES EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 13 Survivor Curve: L5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1992	10,719.95	12.66	0.34	13.00	824.61
1994	20,800.00	11.91	1.09	13.00	1,600.00
Total	31,519.95				2,424.61

Annual Accural Rate ... 7.7 %

Northern Utilities, Inc.
New Hampshire
394.10 (387.00) TOOLS, GARAGE AND SERVICE EQ
Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 2 % *Average Service Life:* 19 *Survivor Curve:* R5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1986	9,950.51	18.60	0.40	19.00	523.71
1987	20,330.96	18.22	0.78	19.00	1,070.05
1988	31,972.29	17.69	1.31	19.00	1,682.75
1989	21,026.41	17.01	1.99	19.00	1,106.65
1990	25,021.33	16.22	2.78	19.00	1,316.91
1991	25,000.14	15.35	3.65	19.00	1,315.80
1992	32,341.83	14.42	4.58	19.00	1,702.20
1993	7,504.82	13.46	5.54	19.00	394.99
1994	12,123.99	12.49	6.51	19.00	638.10
1995	43,537.37	11.49	7.51	19.00	2,291.44
1996	29,496.37	10.50	8.50	19.00	1,552.44
1997	22,755.60	9.50	9.50	19.00	1,197.66
1998	23,225.64	8.50	10.50	19.00	1,222.40
1999	50,066.79	7.50	11.50	19.00	2,635.09
2000	17,936.30	6.50	12.50	19.00	944.02
2001	14,705.49	5.50	13.50	19.00	773.97
2002	8,399.98	4.50	14.50	19.00	442.10
2003	15,486.21	3.50	15.50	19.00	815.06
2004	20,733.84	2.50	16.50	19.00	1,091.25
2005	6,573.99	1.50	17.50	19.00	346.00
Total	438,189.86				23,062.62

Annual Accural Rate ... 5.2 %

Northern Utilities, Inc.
New Hampshire
394.30 (394.00) TOOLS, TOOLS AND OTHER

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 2 % *Average Service Life:* 18 *Survivor Curve:* R5

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1991	2,022.37	15.26	2.74	18.00	112.35
1993	4,904.40	13.44	4.56	18.00	272.47
1994	8,563.18	12.47	5.53	18.00	475.73
1995	12,585.76	11.49	6.51	18.00	699.21
1996	1,245.00	10.50	7.50	18.00	69.17
1998	2,825.00	8.50	9.50	18.00	156.94
2000	4,375.61	6.50	11.50	18.00	243.09
2001	3,468.65	5.50	12.50	18.00	192.70
2004	17,490.20	2.50	15.50	18.00	971.68
2005	1,141.10	1.50	16.50	18.00	63.39
2006	29,350.00	0.50	17.50	18.00	1,630.56
Total	87,971.27				4,887.29

Annual Accural Rate ... 5.4 %

Northern Utilities, Inc.
New Hampshire
396.00 POWER OPERATED EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *10 %* *Average Service Life:* *15* *Survivor Curve:* *R4*

Year	*Original Cost*	*Realized Life*	*Expectancy*	*Avg. Service Life*	*Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1990	52,482.50	14.44	0.56	15.00	3,498.83
1993	10,100.00	12.81	2.19	15.00	673.33
1999	2,289.00	7.47	7.53	15.00	152.60
2000	10,394.99	6.48	8.52	15.00	693.00
Total	75,266.49				5,017.77

Annual Accural Rate ... *6.0 %*

Northern Utilities, Inc.
New Hampshire
397.00 COMMUNICATION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 15 Survivor Curve: R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
1992	65,780.69	13.05	1.95	15.00	4,385.38
1994	17,379.00	11.70	3.30	15.00	1,158.60
1995	36,021.69	10.92	4.08	15.00	2,401.45
1996	8,397.50	10.09	4.91	15.00	559.83
1997	36,160.29	9.22	5.78	15.00	2,410.69
1999	33,240.42	7.38	7.62	15.00	2,216.03
2001	8,875.30	5.45	9.55	15.00	591.69
2003	21,404.62	3.49	11.51	15.00	1,426.97
2004	14,824.61	2.49	12.51	15.00	988.31
2005	46,484.65	1.50	13.50	15.00	3,098.98
2006	32,656.80	0.50	14.50	15.00	2,177.12
Total	321,225.57				21,415.04

Annual Accural Rate ... 6.7 %

Northern Utilities, Inc.
New Hampshire
397.25 COMM EQUIP- METSCAN/TELEMETERING

Original Cost Of Utility Plant In Service
And Development Of Annual Depr Rate as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 10 Survivor Curve: R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
2004	5,312.00	2.49	7.51	10.00	531.20
2005	23,814.60	1.50	8.50	10.00	2,381.46
Total	29,126.60				2,912.66

Annual Accural Rate ... 10.0 %

Northern Utilities, Inc.

New Hampshire

397.35 COMM EQUIP-ITRON EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Annual Depr Rate as of December 31, 2006

Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % *Average Service Life:* 15 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Realized Life (3)	Expectancy (4)	Avg. Service Life (5)	Annual Accruals (6)
2003	1,690,443.22	3.49	11.51	15.00	112,696.21
2004	73,637.00	2.49	12.51	15.00	4,909.13
2005	111,228.94	1.50	13.50	15.00	7,415.26
Total	1,875,309.16				125,020.61

Annual Accural Rate ... 6.7 %

Section 7

Northern Utilities, Inc.
New Hampshire
305.00 PRODUCTION PLANT STRUCTURES

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 %

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
(305-311) PORTSMOUTH (BARBERRY LANE)					
Interim Survivor Curve: None					
Probable Retirement Year:	*2007*				
1994	45,545.45	0.50	13.00	1.00962	45,983
1995	19,413.76	0.50	12.00	1.00625	19,535
1999	10,500.00	0.50	8.00	0.98438	10,336
Total	75,459.21				75,854
(305) BARBERRY LANE (BUTLER BLDG & SITE WORK)					
Interim Survivor Curve: None					
Probable Retirement Year:	*2036*				
1996	2,674.39	29.50	40.00	0.27563	737
1997	560.00	29.50	39.00	0.25577	143
1998	2,274.45	29.50	38.00	0.23487	534
Total	5,508.84				1,415
Account Total	80,968.05				77,269.01

Northern Utilities, Inc.
New Hampshire
311.00 OTHER GAS GENERATING EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -10 %

Year	*Original Cost*	*Expectancy*	*Avg. Service Life*	*Reserve Ratio*	*Calculated Reserve*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*

(305-311) PORTSMOUTH (BARBERRY LANE)

Interim Survivor Curve: None
Probable Retirement Year: 2007

1967	29,291.90	0.50	40.00	1.08625	31,818
1968	4,709.02	0.50	39.00	1.08590	5,114
1970	2,399.49	0.50	37.00	1.08514	2,604
1972	4,370.00	0.50	35.00	1.08429	4,738
1975	425.87	0.50	32.00	1.08281	461
1981	150,358.70	0.50	26.00	1.07885	162,214
1982	147,778.23	0.50	25.00	1.07800	159,305
1983	1,205.82	0.50	24.00	1.07708	1,299
1992	746.40	0.50	15.00	1.06333	794
1993	991.31	0.50	14.00	1.06071	1,052
1994	21,784.54	0.50	13.00	1.05769	23,041
1996	1,333.00	0.50	11.00	1.05000	1,400
1998	8,467.45	0.50	9.00	1.03889	8,797
Total	373,861.73				402,636
Account Total	373,861.73				402,635.65

Northern Utilities, Inc.
New Hampshire
320.00 OTHER PRODUCTION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *0 %* *Average Service Life:* *20* *Survivor Curve:* *R4*

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1990	590.00	5.01	20.00	0.74946	442
1993	6,416.03	7.24	20.00	0.63813	4,094
1998	634.13	11.63	20.00	0.41832	265
Total	7,640.16				4,801.74

Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 20 Survivor Curve: R5

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1974	19,596.83	0.00	0.00	1.00000	19,597
1993	31,847.78	6.64	20.00	0.66816	21,279
1994	5,416.15	7.57	20.00	0.62161	3,367
Total	56,860.76				44,242.98

Northern Utilities, Inc.
New Hampshire
374.40 LAND RIGHTS-OTHER DISTR SYSTEM
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 70 Survivor Curve: R4

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2005	297.50	68.50	70.00	0.02141	6
Total	297.50				6.37

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 %

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
(375.2) DOVER (COCHECO STREET)					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2016					
1957	2,579.00	8.98	48.42	0.85517	2,205
1978	1,906.00	9.09	34.11	0.77028	1,468
Total	4,485.00				3,674
(375.2) EXETER (WATER STREET)					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2014					
1974	400.00	7.23	35.62	0.83689	335
Total	400.00				335
(375.2) PORTSMOUTH (GOVERNOR HOUSE - INSINGTO)					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2016					
1939	646.00	8.89	58.03	0.88910	574
1956	2,332.00	8.98	49.02	0.85765	2,000
Total	2,978.00				2,574
(375.2) SOMERSWORTH					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2016					
1978	867.00	9.09	34.11	0.77028	668

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 %

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
Total	867.00				668
			(375.2) PORTSMOUTH		
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2046					
2006	39,465.14	35.14	35.62	0.01416	559
Total	39,465.14				559
Account Total	48,195.14				7,809.67

Northern Utilities, Inc.
New Hampshire
375.70 (390.00) OTHER DISTRIBUTION SYSTEM STRUCT.
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 %

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
			(375.7) PORTSMOUTH		
Interim Survivor Curve: Iowa		*80 L0*			
Probable Retirement Year:		*2033*			
1988	1,883,351.00	23.65	39.26	0.39760	748,815
1989	39,541.00	23.69	38.55	0.38531	15,236
1990	38,589.00	23.74	37.83	0.37241	14,371
1992	9,564.07	23.84	36.36	0.34451	3,295
1993	67,044.70	23.89	35.62	0.32945	22,088
1994	13,163.86	23.94	34.87	0.31354	4,127
1995	8,284.75	23.99	34.11	0.29669	2,458
1996	71,609.37	24.04	33.34	0.27888	19,971
1997	31,263.62	24.10	32.57	0.26001	8,129
1998	60,287.23	24.16	31.79	0.23997	14,467
1999	2,300.00	24.22	31.00	0.21858	503
2001	2,160.50	24.35	29.39	0.17153	371
2002	15,061.71	24.42	28.58	0.14552	2,192
2004	44,717.46	24.58	26.93	0.08731	3,904
Total	2,286,938.27				859,926
Account Total	2,286,938.27				859,925.94

Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: R3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1966	140,092.68	11.41	45.00	0.93311	130,722
1967	101,495.56	11.98	45.00	0.91720	93,091
1968	82,762.91	12.57	45.00	0.90075	74,548
1969	42,463.72	13.19	45.00	0.88368	37,524
1970	112,924.74	13.82	45.00	0.86618	97,814
1971	45,958.40	14.46	45.00	0.84820	38,982
1972	90,986.98	15.13	45.00	0.82976	75,497
1973	118,589.99	15.81	45.00	0.81080	96,153
1974	113,763.78	16.51	45.00	0.79146	90,040
1975	89,032.13	17.22	45.00	0.77172	68,708
1976	110,744.26	17.94	45.00	0.75158	83,233
1977	70,172.30	18.68	45.00	0.73107	51,301
1978	170,093.56	19.44	45.00	0.71012	120,786
1979	485,519.17	20.20	45.00	0.68887	334,459
1980	55,044.05	20.98	45.00	0.66728	36,730
1981	85,242.07	21.77	45.00	0.64536	55,011
1982	165,308.61	22.57	45.00	0.62306	102,997
1983	55,460.59	23.38	45.00	0.60048	33,303
1984	263,076.83	24.21	45.00	0.57759	151,950
1985	510,555.66	25.04	45.00	0.55440	283,052
1986	288,416.28	25.89	45.00	0.53092	153,126
1987	132,268.64	26.74	45.00	0.50710	67,073
1988	189,300.18	27.61	45.00	0.48304	91,439
1989	342,093.61	28.49	45.00	0.45871	156,921
1990	874,841.15	29.37	45.00	0.43412	379,784
1991	1,060,516.85	30.27	45.00	0.40924	434,006
1992	194,698.61	31.17	45.00	0.38415	74,793
1993	96,355.14	32.08	45.00	0.35882	34,574

Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: R3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1994	79,089.11	33.00	45.00	0.33328	26,358
1995	2,045,335.50	33.93	45.00	0.30752	628,987
1996	2,802,310.83	34.86	45.00	0.28154	788,965
1997	1,123,969.00	35.81	45.00	0.25540	287,059
1998	237,984.69	36.75	45.00	0.22908	54,518
1999	270,358.39	37.71	45.00	0.20260	54,776
2000	426,870.64	38.67	45.00	0.17596	75,112
2001	231,494.17	39.63	45.00	0.14919	34,537
2002	795,988.45	40.60	45.00	0.12230	97,348
2003	309,162.79	41.57	45.00	0.09529	29,461
2004	126,744.67	42.55	45.00	0.06818	8,642
2005	165,062.33	43.53	45.00	0.04096	6,761
2006	469,402.62	44.51	45.00	0.01367	6,418
Total	15,171,551.64				5,546,559.14

Northern Utilities, Inc.
New Hampshire
376.30 (367.60) MAINS - STEEL MAINS (BARE)
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % *Average Service Life:* 31 *Survivor Curve:* L3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1928	4,700.13	0.00	0.00	1.25000	5,875
1939	5,606.76	1.33	31.00	1.19620	6,707
1940	2,130.74	1.52	31.00	1.18884	2,533
1941	10,581.98	1.69	31.00	1.18194	12,507
1945	1,864.64	2.46	31.00	1.15075	2,146
1949	396.19	3.28	31.00	1.11769	443
1950	2,928.75	3.49	31.00	1.10907	3,248
1953	6,912.42	4.16	31.00	1.08237	7,482
1954	8,193.65	4.38	31.00	1.07338	8,795
1955	18,212.50	4.61	31.00	1.06403	19,379
1956	24,138.25	4.85	31.00	1.05452	25,454
1957	10,973.41	5.09	31.00	1.04483	11,465
1958	8,212.92	5.33	31.00	1.03511	8,501
1959	14,280.35	5.58	31.00	1.02511	14,639
1960	7,580.56	5.83	31.00	1.01495	7,694
1961	41,353.10	6.08	31.00	1.00464	41,545
1962	53,666.74	6.34	31.00	0.99422	53,357
1963	109,600.96	6.60	31.00	0.98385	107,831
1964	52,567.84	6.86	31.00	0.97334	51,167
1965	15,874.03	7.12	31.00	0.96288	15,285
2006	10,464.49	30.50	31.00	0.02016	211
Total	410,240.41				406,262.72

Northern Utilities, Inc.
New Hampshire
376.40 (367.70) MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: S2

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1974	2,090.57	17.38	45.00	0.76719	1,604
1975	20,303.65	17.96	45.00	0.75103	15,249
1976	45,911.41	18.56	45.00	0.73437	33,716
1977	54,526.52	19.18	45.00	0.71721	39,107
1978	40,482.33	19.82	45.00	0.69944	28,315
1979	149,554.26	20.48	45.00	0.68120	101,877
1980	171,865.51	21.15	45.00	0.66242	113,848
1981	254,041.77	21.85	45.00	0.64310	163,374
1982	89,847.08	22.57	45.00	0.62314	55,987
1983	143,815.99	23.30	45.00	0.60267	86,674
1984	216,531.46	24.06	45.00	0.58164	125,944
1985	553,824.64	24.84	45.00	0.56006	310,175
1986	565,332.96	25.63	45.00	0.53792	304,105
1987	1,148,683.01	26.45	45.00	0.51515	591,744
1988	1,187,575.44	27.29	45.00	0.49191	584,177
1989	1,084,305.27	28.15	45.00	0.46815	507,614
1990	2,019,092.23	29.02	45.00	0.44389	896,247
1991	3,137,812.86	29.91	45.00	0.41909	1,315,022
1992	2,423,782.75	30.82	45.00	0.39388	954,687
1993	1,749,844.14	31.74	45.00	0.36826	644,399
1994	2,560,031.50	32.68	45.00	0.34225	876,180
1995	1,684,276.30	33.63	45.00	0.31590	532,061
1996	1,264,969.36	34.59	45.00	0.28919	365,820
1997	1,562,482.52	35.56	45.00	0.26225	409,765
1998	1,412,019.85	36.54	45.00	0.23509	331,949
1999	2,000,341.44	37.52	45.00	0.20774	415,546
2000	1,487,746.34	38.51	45.00	0.18023	268,132
2001	1,573,940.09	39.51	45.00	0.15262	240,214

Northern Utilities, Inc.
New Hampshire
376.40 (367.70) MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 45 Survivor Curve: S2

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2002	773,229.24	40.50	45.00	0.12494	96,604
2003	1,228,221.40	41.50	45.00	0.09720	119,386
2004	2,054,811.99	42.50	45.00	0.06944	142,688
2005	2,553,990.23	43.50	45.00	0.04167	106,415
2006	2,698,407.07	44.50	45.00	0.01389	37,478
Total	37,913,691.18				10,816,101.51

Northern Utilities, Inc.
New Hampshire
376.50 (367.20) MAINS - JOINT CLAMPS
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % *Average Service Life:* 15 *Survivor Curve:* S6

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1992	33,444.56	1.15	15.00	1.15393	38,593
1993	85,586.12	1.72	15.00	1.10657	94,707
1994	52,782.68	2.54	15.00	1.03822	54,800
1995	37,918.25	3.50	15.00	0.95806	36,328
1996	64,403.32	4.50	15.00	0.87497	56,351
1997	88,020.77	5.50	15.00	0.79164	69,681
1998	34,253.81	6.50	15.00	0.70831	24,262
1999	9,540.21	7.50	15.00	0.62498	5,962
2000	18,974.49	8.50	15.00	0.54165	10,278
2001	11,620.08	9.50	15.00	0.45832	5,326
2002	7,277.39	10.50	15.00	0.37499	2,729
2003	15,547.56	11.50	15.00	0.29166	4,535
2004	37,630.61	12.50	15.00	0.20833	7,839
2005	44,996.89	13.50	15.00	0.12500	5,624
2006	17,876.00	14.50	15.00	0.04167	745
Total	559,872.74				417,759.89

Northern Utilities, Inc.
New Hampshire
376.60 (367.50) MAINS - CATHODIC PROTECTION
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 18 Survivor Curve: R5

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1991	1,069.53	3.23	18.00	1.02583	1,097
1992	17,059.36	3.96	18.00	0.97468	16,627
1993	17,144.61	4.78	18.00	0.91796	15,738
1994	16,227.44	5.66	18.00	0.85720	13,910
1995	23,991.12	6.58	18.00	0.79333	19,033
1996	10,252.03	7.53	18.00	0.72701	7,453
1997	11,779.22	8.51	18.00	0.65904	7,763
1998	58,435.79	9.50	18.00	0.59012	34,484
1999	29,488.21	10.50	18.00	0.52081	15,358
2000	5,383.56	11.50	18.00	0.45138	2,430
2001	2,582.15	12.50	18.00	0.38194	986
2002	10,631.12	13.50	18.00	0.31249	3,322
2003	30,482.95	14.50	18.00	0.24305	7,409
2004	31,744.74	15.50	18.00	0.17361	5,511
2005	17,549.14	16.50	18.00	0.10416	1,828
2006	24,946.29	17.50	18.00	0.03472	866
Total	308,767.26				153,816.27

Northern Utilities, Inc.
New Hampshire
376.80 (367.10) MAINS - CAST IRON

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -25 % Average Service Life: 62 Survivor Curve: S5

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1939	44,883.68	4.22	62.00	1.16496	52,288
1941	31,933.64	4.75	62.00	1.15425	36,859
1945	3,762.08	6.07	62.00	1.12760	4,242
1953	5,448.72	10.22	62.00	1.04386	5,688
2003	1,685.27	58.50	62.00	0.07056	119
Total	87,713.39				99,195.67

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 % Average Service Life: 30 Survivor Curve: R3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1956	3,711.71	0.50	30.00	1.03250	3,832
1970	3,806.03	3.63	30.00	0.92286	3,512
1971	1,106.53	3.93	30.00	0.91232	1,010
1973	2,969.09	4.61	30.00	0.88871	2,639
1974	9,065.61	4.98	30.00	0.87553	7,937
1978	11,927.96	6.80	30.00	0.81207	9,686
1979	25,491.70	7.33	30.00	0.79346	20,227
1980	5,454.31	7.89	30.00	0.77372	4,220
1981	1,655.91	8.49	30.00	0.75299	1,247
1985	17,703.88	11.12	30.00	0.66070	11,697
1986	26,442.33	11.84	30.00	0.63553	16,805
1988	20,534.24	13.34	30.00	0.58314	11,974
1989	30,889.02	14.12	30.00	0.55589	17,171
1990	122,239.45	14.91	30.00	0.52806	64,550
1991	99,745.76	15.73	30.00	0.49962	49,835
1992	38,665.95	16.56	30.00	0.47056	18,195
1993	47,418.82	17.40	30.00	0.44096	20,910
1994	112,232.69	18.26	30.00	0.41083	46,109
1995	116,805.19	19.14	30.00	0.38015	44,403
1996	193,131.71	20.03	30.00	0.34900	67,403
1997	147,291.23	20.93	30.00	0.31739	46,749
1998	110,779.24	21.85	30.00	0.28532	31,607
1999	174,530.40	22.78	30.00	0.25286	44,133
2000	257,845.24	23.71	30.00	0.22005	56,738
2001	50,602.99	24.66	30.00	0.18687	9,456
2002	15,958.64	25.62	30.00	0.15341	2,448
2003	90,791.33	26.58	30.00	0.11969	10,867
2004	124,267.03	27.55	30.00	0.08572	10,652

Northern Utilities, Inc.

New Hampshire

378.20 (369.00) PUMPING AND REG. STATION EQ.

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2006

Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -5 % Average Service Life: 30 Survivor Curve: R3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2005	90,181.40	28.53	30.00	0.05156	4,650
Total	1,953,245.39				640,661.38

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *-85 %* *Average Service Life:* *47* *Survivor Curve:* *R3*

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1934	82.71	1.68	47.00	1.78404	148
1939	235.82	2.94	47.00	1.73411	409
1940	22.32	3.19	47.00	1.72442	38
1944	209.14	4.22	47.00	1.68372	352
1945	449.18	4.49	47.00	1.67343	752
1946	166.67	4.75	47.00	1.66299	277
1947	1,279.67	5.02	47.00	1.65235	2,114
1948	1,242.05	5.29	47.00	1.64164	2,039
1949	940.92	5.58	47.00	1.63036	1,534
1951	237.14	6.19	47.00	1.60647	381
1952	1,000.62	6.51	47.00	1.59375	1,595
1953	2,629.39	6.85	47.00	1.58043	4,156
1954	1,279.65	7.20	47.00	1.56647	2,005
1955	1,194.97	7.58	47.00	1.55183	1,854
1956	3,198.67	7.97	47.00	1.53647	4,915
1957	9,973.06	8.38	47.00	1.52035	15,163
1958	7,951.87	8.80	47.00	1.50345	11,955
1959	8,345.68	9.25	47.00	1.48578	12,400
1960	7,224.12	9.72	47.00	1.46731	10,600
1961	14,677.44	10.21	47.00	1.44804	21,254
1962	23,628.48	10.72	47.00	1.42798	33,741
1963	16,545.16	11.25	47.00	1.40714	23,281
1964	29,974.11	11.80	47.00	1.38540	41,526
1965	23,195.94	12.37	47.00	1.36300	31,616
1966	21,044.96	12.96	47.00	1.33985	28,197
1967	27,917.62	13.57	47.00	1.31599	36,739
Total	204,647.36				289,040.39

Northern Utilities, Inc.
New Hampshire
380.20 SERVICES - COATED STEEL NOT WRAPPED
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -85 % Average Service Life: 38 Survivor Curve: L3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1968	15,732.31	11.33	38.00	1.29839	20,427
1969	6,769.19	11.50	38.00	1.29015	8,733
1970	8,802.96	11.67	38.00	1.28177	11,283
1971	20,161.77	11.86	38.00	1.27277	25,661
1972	34,970.27	12.06	38.00	1.26289	44,164
1973	39,169.64	12.28	38.00	1.25200	49,040
1974	54,640.18	12.53	38.00	1.23976	67,741
1975	30,770.53	12.82	38.00	1.22596	37,723
1976	42,873.29	13.14	38.00	1.21036	51,892
Total	253,890.14				316,664.60

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -10 % *Average Service Life:* 32 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2003	553,688.30	28.51	32.00	0.12010	66,500
2004	515,468.03	29.50	32.00	0.08582	44,238
2005	1,309,619.49	30.50	32.00	0.05151	67,455
2006	69,475.16	31.50	32.00	0.01717	1,193
Total	9,196,255.72				2,765,268.24

Northern Utilities, Inc.
New Hampshire
383.00 GAS REGULATORS

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *0 %* *Average Service Life: 30* *Survivor Curve: R3*

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1999	6,775.57	22.78	30.00	0.24082	1,632
2000	3,744.90	23.71	30.00	0.20957	785
2001	134,243.25	24.66	30.00	0.17797	23,892
2002	350.30	25.62	30.00	0.14611	51
2003	542.83	26.58	30.00	0.11399	62
2004	39,538.37	27.55	30.00	0.08164	3,228
Total	185,195.22				29,649.06

Northern Utilities, Inc.
New Hampshire
386.12 (386.1 &.2) MISC. PROP ON CUST'S PREM. (WH & CB)
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 5 % *Average Service Life:* 10 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1994	132,012.00	2.22	10.00	0.73892	97,547
1995	36,637.21	2.59	10.00	0.70418	25,799
1996	143,045.25	3.00	10.00	0.66487	95,107
1997	78,551.57	3.47	10.00	0.62059	48,748
1998	79,350.45	3.99	10.00	0.57128	45,331
1999	82,649.77	4.56	10.00	0.51714	42,742
2000	158,585.31	5.17	10.00	0.45854	72,718
2001	94,028.25	5.83	10.00	0.39592	37,228
2002	92,107.97	6.53	10.00	0.32978	30,376
2003	51,285.88	7.26	10.00	0.26066	13,368
2004	77,781.74	8.01	10.00	0.18901	14,702
2005	63,111.46	8.79	10.00	0.11508	7,263
2006	70,450.17	9.59	10.00	0.03892	2,742
Total	1,159,597.03				533,670.58

Northern Utilities, Inc.
New Hampshire
391.10 (391.10) OFFICE FURN & EQ-UNSPECIFIED

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 2 % Average Service Life: 11 Survivor Curve: S3

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1994	55,521.82	1.70	11.00	0.82849	45,999
1995	287,709.13	2.02	11.00	0.80034	230,266
1996	72,621.13	2.39	11.00	0.76676	55,683
1997	26,919.23	2.85	11.00	0.72652	19,557
1998	15,109.87	3.39	11.00	0.67839	10,250
1999	30,754.11	4.03	11.00	0.62133	19,108
2002	67,792.64	6.54	11.00	0.39760	26,955
Total	556,427.93				407,818.32

Northern Utilities, Inc.
New Hampshire
391.11 (391.10 & 20) OFFICE FURN & EQ-DATA HANDLING EQ
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 10 Survivor Curve: R4

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2004	7,565.50	7.51	10.00	0.24875	1,882
Total	7,565.50				1,881.93

Northern Utilities, Inc.

New Hampshire

391.12 (391.30) INFORMATION SYSTEMS

Original Cost Of Utility Plant In Service

And Development Of Calculated Depr Reserve as of December 31, 2006

Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 8 Survivor Curve: L4

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2002	17,724.71	3.61	8.00	0.54930	9,736
2003	31,532.72	4.52	8.00	0.43500	13,717
2004	5,250.00	5.50	8.00	0.31243	1,640
2005	69,362.10	6.50	8.00	0.18750	13,006
Total	123,869.53				38,098.66

Northern Utilities, Inc.
New Hampshire
392.00 TRANSPORTATION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *10 %* *Average Service Life:* *9* *Survivor Curve:* *L4*

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1995	27,479.29	1.38	9.00	0.76157	20,927
1996	5,005.89	1.59	9.00	0.74103	3,709
1999	2,290.91	2.27	9.00	0.67317	1,542
2001	3,900.00	3.68	9.00	0.53172	2,074
Total	38,676.09				28,252.81

Northern Utilities, Inc.
New Hampshire
393.00 STORES EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 13 Survivor Curve: L5

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1992	10,719.95	1.62	13.00	0.87515	9,382
1994	20,800.00	1.88	13.00	0.85516	17,787
Total	31,519.95				27,168.91

Northern Utilities, Inc.
New Hampshire
394.10 (387.00) TOOLS, GARAGE AND SERVICE EQ
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 2 % Average Service Life: 19 Survivor Curve: R5

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1986	9,950.51	1.36	19.00	0.91001	9,055
1987	20,330.96	1.70	19.00	0.89215	18,138
1988	31,972.29	2.14	19.00	0.86950	27,800
1989	21,026.41	2.68	19.00	0.84190	17,702
1990	25,021.33	3.31	19.00	0.80926	20,249
1991	25,000.14	4.03	19.00	0.77193	19,298
1992	32,341.83	4.84	19.00	0.73053	23,627
1993	7,504.82	5.70	19.00	0.68614	5,149
1994	12,123.99	6.60	19.00	0.63937	7,752
1995	43,537.37	7.55	19.00	0.59072	25,718
1996	29,496.37	8.52	19.00	0.54065	15,947
1997	22,755.60	9.51	19.00	0.48974	11,144
1998	23,225.64	10.50	19.00	0.43837	10,181
1999	50,066.79	11.50	19.00	0.38683	19,368
2000	17,936.30	12.50	19.00	0.33526	6,013
2001	14,705.49	13.50	19.00	0.28368	4,172
2002	8,399.98	14.50	19.00	0.23210	1,950
2003	15,486.21	15.50	19.00	0.18052	2,796
2004	20,733.84	16.50	19.00	0.12895	2,674
2005	6,573.99	17.50	19.00	0.07737	509
Total	438,189.86				249,242.02

Northern Utilities, Inc.
New Hampshire
394.30 (394.00) TOOLS, TOOLS AND OTHER

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 2 % *Average Service Life:* 18 *Survivor Curve:* R5

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1991	2,022.37	3.23	18.00	0.80425	1,626
1993	4,904.40	4.78	18.00	0.71968	3,530
1994	8,563.18	5.66	18.00	0.67204	5,755
1995	12,585.76	6.58	18.00	0.62197	7,828
1996	1,245.00	7.53	18.00	0.56997	710
1998	2,825.00	9.50	18.00	0.46266	1,307
2000	4,375.61	11.50	18.00	0.35388	1,548
2001	3,468.65	12.50	18.00	0.29944	1,039
2004	17,490.20	15.50	18.00	0.13611	2,381
2005	1,141.10	16.50	18.00	0.08167	93
2006	29,350.00	17.50	18.00	0.02722	799
Total	87,971.27				26,615.25

Northern Utilities, Inc.
New Hampshire
396.00 POWER OPERATED EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 10 % *Average Service Life:* 15 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1990	52,482.50	1.64	15.00	0.80184	42,082
1993	10,100.00	3.02	15.00	0.71855	7,257
1999	2,289.00	7.68	15.00	0.43913	1,005
2000	10,394.99	8.61	15.00	0.38352	3,987
Total	75,266.49				54,331.60

Northern Utilities, Inc.
New Hampshire
397.00 COMMUNICATION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *0 %* *Average Service Life:* *10* *Survivor Curve:* *L3*

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1992	65,780.69	2.04	10.00	0.79641	52,388
1994	17,379.00	2.54	10.00	0.74585	12,962
1995	36,021.69	2.76	10.00	0.72381	26,073
1996	8,397.50	2.94	10.00	0.70570	5,926
1997	36,160.29	3.11	10.00	0.68887	24,910
1999	33,240.42	3.67	10.00	0.63293	21,039
2001	8,875.30	4.87	10.00	0.51314	4,554
2003	21,404.62	6.58	10.00	0.34235	7,328
2004	14,824.61	7.52	10.00	0.24804	3,677
2005	46,484.65	8.50	10.00	0.14988	6,967
2006	32,656.80	9.50	10.00	0.05000	1,633
Total	321,225.57				167,457.21

Northern Utilities, Inc.
New Hampshire
397.25 COMM EQUIP- METSCAN/TELEMETERING
Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 10 Survivor Curve: R3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2004	5,312.00	7.59	10.00	0.24077	1,279
2005	23,814.60	8.54	10.00	0.14609	3,479
Total	29,126.60				4,757.95

Northern Utilities, Inc.
New Hampshire
397.35 COMM EQUIP-ITRON EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: 0 % Average Service Life: 15 Survivor Curve: R3

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
2003	1,690,443.22	11.62	15.00	0.22521	380,707
2004	73,637.00	12.57	15.00	0.16207	11,935
2005	111,228.94	13.53	15.00	0.09783	10,882
Total	1,875,309.16				403,523.24

Northern Utilities, Inc.
New Hampshire
380.30 SERVICES - STEEL COATED & WRAPPED

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -85 % Average Service Life: 38 Survivor Curve: R1.5

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1977	9,335.25	16.70	38.00	1.03697	9,680
1978	11,169.74	17.29	38.00	1.00823	11,262
1979	54,754.30	17.89	38.00	0.97891	53,600
1980	13,755.97	18.51	38.00	0.94905	13,055
1981	30,132.08	19.13	38.00	0.91857	27,678
1982	22,976.16	19.77	38.00	0.88756	20,393
Total	142,123.50				135,667.81

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -85 % Average Service Life: 40 Survivor Curve: R3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1970	3,966.00	9.86	40.00	1.39384	5,528
1971	11,065.43	10.43	40.00	1.36783	15,136
1972	12,918.44	11.01	40.00	1.34069	17,320
1973	13,966.36	11.62	40.00	1.31266	18,333
1974	21,594.66	12.25	40.00	1.28356	27,718
1975	14,346.70	12.89	40.00	1.25365	17,986
1976	14,112.13	13.56	40.00	1.22276	17,256
1977	70,348.78	14.25	40.00	1.19114	83,795
1978	71,624.86	14.95	40.00	1.15862	82,986
1979	319,202.09	15.67	40.00	1.12545	359,245
1980	141,044.76	16.40	40.00	1.09145	153,944
1981	178,978.26	17.15	40.00	1.05685	189,153
1982	149,474.60	17.91	40.00	1.02149	152,687
1983	142,428.17	18.69	40.00	0.98556	140,372
1984	187,877.35	19.48	40.00	0.94893	178,282
1985	341,211.93	20.29	40.00	0.91176	311,103
1986	487,817.80	21.10	40.00	0.87393	426,318
1987	665,352.52	21.93	40.00	0.83559	555,959
1988	818,982.94	22.78	40.00	0.79662	652,416
1989	822,528.43	23.63	40.00	0.75716	622,789
1990	1,373,114.41	24.49	40.00	0.71712	984,694
1991	1,331,985.80	25.37	40.00	0.67663	901,261
1992	1,157,850.49	26.26	40.00	0.63559	735,918
1993	855,770.82	27.15	40.00	0.59413	508,439
1994	1,831,662.53	28.06	40.00	0.55217	1,011,393
1995	919,616.07	28.98	40.00	0.50983	468,850
1996	1,139,530.59	29.90	40.00	0.46705	532,215
1997	1,171,892.89	30.83	40.00	0.42392	496,793

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -85 % Average Service Life: 40 Survivor Curve: R3

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1998	1,082,154.35	31.77	40.00	0.38041	411,663
1999	946,135.44	32.72	40.00	0.33660	318,472
2000	936,245.47	33.68	40.00	0.29246	273,818
2001	726,634.04	34.64	40.00	0.24807	180,260
2002	1,137,613.32	35.60	40.00	0.20341	231,402
2003	853,184.70	36.57	40.00	0.15854	135,265
2004	1,017,037.72	37.55	40.00	0.11345	115,382
2005	1,208,829.75	38.53	40.00	0.06819	82,434
2006	1,139,416.28	39.51	40.00	0.02276	25,936
Total	23,317,516.88				11,442,518.09

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *0 %* *Average Service Life: 30* *Survivor Curve:* *R5*

Year (1)	*Original Cost* (2)	*Expectancy* (3)	*Avg. Service Life* (4)	*Reserve Ratio* (5)	*Calculated Reserve* (6)
1975	19,604.20	2.39	30.00	0.92030	18,042
1976	53,597.72	2.78	30.00	0.90741	48,635
1977	90,768.28	3.22	30.00	0.89256	81,016
1978	111,830.67	3.73	30.00	0.87576	97,937
1979	146,035.82	4.29	30.00	0.85695	125,146
1980	1,500.00	4.92	30.00	0.83597	1,254
1981	267,176.76	5.61	30.00	0.81314	217,253
1982	51,285.89	6.34	30.00	0.78851	40,439
1983	50,588.50	7.14	30.00	0.76214	38,556
1984	13,043.24	7.97	30.00	0.73449	9,580
1985	96,499.57	8.83	30.00	0.70566	68,096
1986	24,606.27	9.73	30.00	0.67578	16,629
1987	76,664.32	10.65	30.00	0.64510	49,456
1988	48,784.97	11.59	30.00	0.61369	29,939
1989	94,748.62	12.55	30.00	0.58163	55,109
1990	214,954.67	13.53	30.00	0.54913	118,037
1991	193,803.31	14.51	30.00	0.51627	100,055
1992	19,238.04	15.50	30.00	0.48317	9,295
1993	30,733.71	16.50	30.00	0.44995	13,829
1994	126,429.50	17.50	30.00	0.41666	52,678
1995	84,769.61	18.50	30.00	0.38333	32,495
1996	44,416.21	19.50	30.00	0.35000	15,546
1997	136,809.65	20.50	30.00	0.31667	43,323
1998	13,594.44	21.50	30.00	0.28334	3,852
1999	64,015.52	22.50	30.00	0.25000	16,004
2000	10,903.22	23.50	30.00	0.21667	2,362
2001	34,537.54	24.50	30.00	0.18333	6,332
2002	31,004.04	25.50	30.00	0.15000	4,651

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: *0 %* *Average Service Life:* *30* *Survivor Curve:* *R5*

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
2003	44,940.50	26.50	30.00	0.11667	5,243
2004	54,874.03	27.50	30.00	0.08333	4,573
2005	180,263.73	28.50	30.00	0.05000	9,013
Total	2,432,022.55				1,334,374.03

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Original Cost Of Utility Plant In Service
And Development Of Calculated Depr Reserve as of December 31, 2006
Based Upon Broad Group/Whole Life Procedure and Technique

Salvage Value: -10 % Average Service Life: 32 Survivor Curve: R4

Year (1)	Original Cost (2)	Expectancy (3)	Avg. Service Life (4)	Reserve Ratio (5)	Calculated Reserve (6)
1975	11,847.40	4.93	32.00	0.93051	11,024
1976	14,147.41	5.45	32.00	0.91282	12,914
1977	14,353.71	6.01	32.00	0.89339	12,823
1978	21,154.92	6.62	32.00	0.87238	18,455
1979	52,090.16	7.27	32.00	0.85010	44,282
1980	39,693.16	7.94	32.00	0.82689	32,822
1981	45,691.70	8.64	32.00	0.80295	36,688
1982	40,772.86	9.36	32.00	0.77826	31,732
1983	34,439.17	10.10	32.00	0.75270	25,922
1984	32,808.52	10.87	32.00	0.72639	23,832
1985	49,790.75	11.66	32.00	0.69927	34,817
1986	102,781.14	12.47	32.00	0.67135	69,003
1987	113,561.02	13.30	32.00	0.64266	72,982
1988	157,188.44	14.16	32.00	0.61324	96,394
1989	241,895.26	15.04	32.00	0.58313	141,056
1990	327,606.07	15.93	32.00	0.55238	180,964
1991	340,875.43	16.84	32.00	0.52102	177,604
1992	357,389.31	17.77	32.00	0.48919	174,830
1993	366,563.52	18.71	32.00	0.45689	167,480
1994	425,505.55	19.66	32.00	0.42420	180,501
1995	359,183.25	20.62	32.00	0.39118	140,505
1996	389,507.50	21.59	32.00	0.35787	139,392
1997	454,996.44	22.57	32.00	0.32432	147,564
1998	560,301.30	23.55	32.00	0.29058	162,811
1999	568,345.43	24.53	32.00	0.25667	145,878
2000	535,732.98	25.52	32.00	0.22265	119,282
2001	471,499.12	26.52	32.00	0.18854	88,895
2002	618,283.22	27.51	32.00	0.15435	95,430

Section 8

Northern Utilities, Inc.
New Hampshire
305.00 PRODUCTION PLANT STRUCTURES
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
		(305-311) PORTSMOUTH (BARBERRY LANE)			
Interim Survivor Curve: None					
Probable Retirement Year:		*2007*			
1994	45,545.45	13.00	3,503.50	0.50	1,751.75
1995	19,413.76	12.00	1,617.81	0.50	808.91
1999	10,500.00	8.00	1,312.50	0.50	656.25
Total	75,459.21	11.73	6,433.81	0.50	3,216.90
		(305) BARBERRY LANE (BUTLER BLDG & SITE WORK)			
Interim Survivor Curve: None					
Probable Retirement Year:		*2036*			
1996	2,674.39	40.00	66.86	29.50	1,972.36
1997	560.00	39.00	14.36	29.50	423.59
1998	2,274.45	38.00	59.85	29.50	1,765.69
Total	5,508.84	39.05	141.07	29.50	4,161.64
Account Total	80,968.05	12.31	6,574.88	1.12	7,378.55

Composite Average Remaining Life ... 1.1 Years

Northern Utilities, Inc.

New Hampshire

311.00 OTHER GAS GENERATING EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2006

Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
		(305-311) PORTSMOUTH (BARBERRY LANE)			
Interim Survivor Curve: None					
Probable Retirement Year:	2007				
1967	29,291.90	40.00	732.30	0.50	366.15
1968	4,709.02	39.00	120.74	0.50	60.37
1970	2,399.49	37.00	64.85	0.50	32.43
1972	4,370.00	35.00	124.86	0.50	62.43
1975	425.87	32.00	13.31	0.50	6.65
1981	150,358.70	26.00	5,783.03	0.50	2,891.51
1982	147,778.23	25.00	5,911.13	0.50	2,955.56
1983	1,205.82	24.00	50.24	0.50	25.12
1992	746.40	15.00	49.76	0.50	24.88
1993	991.31	14.00	70.81	0.50	35.40
1994	21,784.54	13.00	1,675.73	0.50	837.87
1996	1,333.00	11.00	121.18	0.50	60.59
1998	8,467.45	9.00	940.83	0.50	470.41
Total	373,861.73	23.88	15,658.77	0.50	7,829.38
Account Total	373,861.73	23.88	15,658.77	0.50	7,829.38

Composite Average Remaining Life ... *0.5 Years*

Northern Utilities, Inc.
New Hampshire
320.00 OTHER PRODUCTION EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1990	590.00	20.00	29.50	5.01	147.82
1993	6,416.03	20.00	320.80	7.24	2,321.74
1998	634.13	20.00	31.71	11.63	368.86
Total	7,640.16	20.00	382.01	7.43	2,838.42

Composite Average Remaining Life ... 7.43 *Years*

Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: *20* *Survivor Curve:* *R5*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
1974	19,596.83	0.00	0.00	0.00	0.00
1993	31,847.78	20.00	1,592.41	6.64	10,568.37
1994	5,416.15	20.00	270.81	7.57	2,049.42
Total	56,860.76	13.33	1,863.22	6.77	12,617.78

Composite Average Remaining Life ... *6.77* *Years*

Northern Utilities, Inc.
New Hampshire
374.40 LAND RIGHTS-OTHER DISTR SYSTEM
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 70 *Survivor Curve: R4*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2005	297.50	70.00	4.25	68.50	291.13
Total	297.50	70.00	4.25	68.50	291.13

Composite Average Remaining Life ... 68.5 Years

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
(375.2) DOVER (COCHECO STREET)					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2016					
1957	2,579.00	48.42	53.26	8.98	478.54
1978	1,906.00	34.11	55.88	9.09	507.76
Total	4,485.00	41.09	109.14	9.04	986.29
(375.2) EXETER (WATER STREET)					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2014					
1974	400.00	35.62	11.23	7.23	81.18
Total	400.00	35.62	11.23	7.23	81.18
(375.2) PORTSMOUTH (GOVERNOR HOUSE - INSINGTO)					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2016					
1939	646.00	58.03	11.13	8.89	98.99
1956	2,332.00	49.02	47.58	8.98	427.20
Total	2,978.00	50.73	58.71	8.96	526.19
(375.2) SOMERSWORTH					
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2016					
1978	867.00	34.11	25.42	9.09	230.97
Total	867.00	34.11	25.42	9.09	230.97

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
			(375.2) PORTSMOUTH		
Interim Survivor Curve: Iowa 80 L0					
Probable Retirement Year: 2046					
2006	39,465.14	35.62	1,107.95	35.14	38,932.75
Total	39,465.14	35.62	1,107.95	35.14	38,932.75
Account Total	48,195.14	36.72	1,312.45	31.05	40,757.39

Composite Average Remaining Life ... 31.1 Years

Northern Utilities, Inc.
New Hampshire
375.70 (390.00) OTHER DISTRIBUTION SYSTEM STRUCT.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
			(375.7) PORTSMOUTH		
Interim Survivor Curve: Iowa		*80 L0*			
Probable Retirement Year:		*2033*			
1988	1,883,351.00	39.26	47,971.83	23.65	1,134,536.22
1989	39,541.00	38.55	1,025.78	23.69	24,305.33
1990	38,589.00	37.83	1,020.14	23.74	24,218.03
1992	9,564.07	36.36	263.01	23.84	6,269.12
1993	67,044.70	35.62	1,882.22	23.89	44,957.13
1994	13,163.86	34.87	377.53	23.94	9,036.41
1995	8,284.75	34.11	242.89	23.99	5,826.74
1996	71,609.37	33.34	2,147.69	24.04	51,638.59
1997	31,263.62	32.57	959.95	24.10	23,134.71
1998	60,287.23	31.79	1,896.70	24.16	45,819.90
1999	2,300.00	31.00	74.21	24.22	1,797.25
2001	2,160.50	29.39	73.51	24.35	1,789.90
2002	15,061.71	28.58	527.04	24.42	12,869.94
2004	44,717.46	26.93	1,660.60	24.58	40,813.12
Total	2,286,938.27	38.04	60,123.10	23.73	1,427,012.40
Account Total	2,286,938.27	38.04	60,123.10	23.73	1,427,012.40

Composite Average Remaining Life ... *23.7 Years*

Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1966	140,092.68	45.00	3,113.17	11.41	35,515.18
1967	101,495.56	45.00	2,255.46	11.98	27,022.38
1968	82,762.91	45.00	1,839.17	12.57	23,124.18
1969	42,463.72	45.00	943.64	13.19	12,444.17
1970	112,924.74	45.00	2,509.44	13.82	34,673.94
1971	45,958.40	45.00	1,021.30	14.46	14,772.80
1972	90,986.98	45.00	2,021.93	15.13	30,589.29
1973	118,589.99	45.00	2,635.33	15.81	41,667.99
1974	113,763.78	45.00	2,528.08	16.51	41,732.14
1975	89,032.13	45.00	1,978.49	17.22	34,066.08
1976	110,744.26	45.00	2,460.98	17.94	44,157.66
1977	70,172.30	45.00	1,559.38	18.68	29,131.76
1978	170,093.56	45.00	3,779.85	19.44	73,464.42
1979	485,519.17	45.00	10,789.31	20.20	217,952.10
1980	55,044.05	45.00	1,223.20	20.98	25,660.30
1981	85,242.07	45.00	1,894.27	21.77	41,232.92
1982	165,308.61	45.00	3,673.52	22.57	82,911.32
1983	55,460.59	45.00	1,232.46	23.38	28,818.36
1984	263,076.83	45.00	5,846.15	24.21	141,516.60
1985	510,555.66	45.00	11,345.67	25.04	284,113.72
1986	288,416.28	45.00	6,409.25	25.89	165,915.81
1987	132,268.64	45.00	2,939.30	26.74	78,610.10
1988	189,300.18	45.00	4,206.67	27.61	116,148.89
1989	342,093.61	45.00	7,602.08	28.49	216,556.75
1990	874,841.15	45.00	19,440.90	29.37	571,013.89
1991	1,060,516.85	45.00	23,567.03	30.27	713,312.05
1992	194,698.61	45.00	4,326.63	31.17	134,864.56

Northern Utilities, Inc.
New Hampshire
376.20 (367.40) MAINS - STEEL (COATED & WRAPPED)

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve: R3*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
1993	96,355.14	45.00	2,141.22	32.08	68,695.79
1994	79,089.11	45.00	1,757.53	33.00	58,002.31
1995	2,045,335.50	45.00	45,451.87	33.93	1,542,145.81
1996	2,802,310.83	45.00	62,273.54	34.86	2,171,139.17
1997	1,123,969.00	45.00	24,977.07	35.81	894,321.95
1998	237,984.69	45.00	5,288.55	36.75	194,370.34
1999	270,358.39	45.00	6,007.96	37.71	226,537.63
2000	426,870.64	45.00	9,486.01	38.67	366,780.74
2001	231,494.17	45.00	5,144.31	39.63	203,864.50
2002	795,988.45	45.00	17,688.62	40.60	718,109.72
2003	309,162.79	45.00	6,870.28	41.57	285,594.35
2004	126,744.67	45.00	2,816.55	42.55	119,831.46
2005	165,062.33	45.00	3,668.05	43.53	159,653.15
2006	469,402.62	45.00	10,431.16	44.51	464,268.04
Total	15,171,551.64	45.00	337,145.40	31.84	10,734,304.33

Composite Average Remaining Life ... 31.8 Years

Northern Utilities, Inc.
New Hampshire
376.30 (367.60) MAINS - STEEL MAINS (BARE)
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 31 *Survivor Curve: L3*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
1928	4,700.13	0.00	0.00	0.00	0.00
1939	5,606.76	31.00	180.87	1.33	241.30
1940	2,130.74	31.00	68.73	1.52	104.26
1941	10,581.98	31.00	341.36	1.69	576.19
1945	1,864.64	31.00	60.15	2.46	148.05
1949	396.19	31.00	12.78	3.28	41.94
1950	2,928.75	31.00	94.48	3.49	330.19
1953	6,912.42	31.00	222.99	4.16	926.96
1954	8,193.65	31.00	264.32	4.38	1,157.75
1955	18,212.50	31.00	587.51	4.61	2,709.56
1956	24,138.25	31.00	778.67	4.85	3,774.92
1957	10,973.41	31.00	353.99	5.09	1,801.12
1958	8,212.92	31.00	264.94	5.33	1,411.91
1959	14,280.35	31.00	460.66	5.58	2,569.21
1960	7,580.56	31.00	244.54	5.83	1,425.46
1961	41,353.10	31.00	1,333.99	6.08	8,117.02
1962	53,666.74	31.00	1,731.21	6.34	10,981.48
1963	109,600.96	31.00	3,535.58	6.60	23,336.42
1964	52,567.84	31.00	1,695.77	6.86	11,634.59
1965	15,874.03	31.00	512.07	7.12	3,646.22
2006	10,464.49	31.00	337.57	30.50	10,295.71
Total	410,240.41	29.52	13,082.17	6.51	85,230.24

Composite Average Remaining Life ... 6.51 Years

Northern Utilities, Inc.
New Hampshire
376.40 (367.70) MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45 *Survivor Curve:* S2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1974	2,090.57	45.00	46.46	17.38	807.48
1975	20,303.65	45.00	451.19	17.96	8,104.75
1976	45,911.41	45.00	1,020.25	18.56	18,938.50
1977	54,526.52	45.00	1,211.70	19.18	23,240.85
1978	40,482.33	45.00	899.61	19.82	17,830.28
1979	149,554.26	45.00	3,323.43	20.48	68,052.75
1980	171,865.51	45.00	3,819.23	21.15	80,787.11
1981	254,041.77	45.00	5,645.37	21.85	123,342.66
1982	89,847.08	45.00	1,996.60	22.57	45,057.33
1983	143,815.99	45.00	3,195.91	23.30	74,477.01
1984	216,531.46	45.00	4,811.81	24.06	115,775.98
1985	553,824.64	45.00	12,307.22	24.84	305,684.34
1986	565,332.96	45.00	12,562.96	25.63	322,048.57
1987	1,148,683.01	45.00	25,526.29	26.45	675,287.86
1988	1,187,575.44	45.00	26,390.57	27.29	720,233.89
1989	1,084,305.27	45.00	24,095.67	28.15	678,214.35
1990	2,019,092.23	45.00	44,868.72	29.02	1,302,094.50
1991	3,137,812.86	45.00	69,729.18	29.91	2,085,795.62
1992	2,423,782.75	45.00	53,861.84	30.82	1,660,032.79
1993	1,749,844.14	45.00	38,885.43	31.74	1,234,325.18
1994	2,560,031.50	45.00	56,889.59	32.68	1,859,087.25
1995	1,684,276.30	45.00	37,428.36	33.63	1,258,627.87
1996	1,264,969.36	45.00	28,110.43	34.59	972,313.75
1997	1,562,482.52	45.00	34,721.84	35.56	1,234,670.19
1998	1,412,019.85	45.00	31,378.22	36.54	1,146,460.83
1999	2,000,341.44	45.00	44,452.04	37.52	1,667,904.45
2000	1,487,746.34	45.00	33,061.03	38.51	1,273,240.79

Northern Utilities, Inc.
New Hampshire
376.40 (367.70) MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: *45* *Survivor Curve:* *S2*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
2001	1,573,940.09	45.00	34,976.45	39.51	1,381,769.29
2002	773,229.24	45.00	17,182.87	40.50	695,946.35
2003	1,228,221.40	45.00	27,293.81	41.50	1,132,712.82
2004	2,054,811.99	45.00	45,662.49	42.50	1,940,661.66
2005	2,553,990.23	45.00	56,755.34	43.50	2,468,858.16
2006	2,698,407.07	45.00	59,964.61	44.50	2,668,424.80
Total	37,913,691.18	45.00	842,526.53	34.73	29,260,809.97

Composite Average Remaining Life ... *34.7* *Years*

Northern Utilities, Inc.
New Hampshire
376.50 (367.20) MAINS - JOINT CLAMPS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 15 *Survivor Curve:* S6

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	33,444.56	15.00	2,229.57	1.15	2,570.33
1993	85,586.12	15.00	5,705.57	1.72	9,820.24
1994	52,782.68	15.00	3,518.74	2.54	8,942.66
1995	37,918.25	15.00	2,527.81	3.50	8,856.03
1996	64,403.32	15.00	4,293.42	4.50	19,322.75
1997	88,020.77	15.00	5,867.87	5.50	32,276.00
1998	34,253.81	15.00	2,283.52	6.50	14,843.92
1999	9,540.21	15.00	635.99	7.50	4,770.25
2000	18,974.49	15.00	1,264.93	8.50	10,752.46
2001	11,620.08	15.00	774.65	9.50	7,359.52
2002	7,277.39	15.00	485.14	10.50	5,094.24
2003	15,547.56	15.00	1,036.47	11.50	11,919.91
2004	37,630.61	15.00	2,508.63	12.50	31,359.03
2005	44,996.89	15.00	2,999.70	13.50	40,497.34
2006	17,876.00	15.00	1,191.70	14.50	17,280.15
Total	559,872.74	15.00	37,323.70	6.05	225,664.83

Composite Average Remaining Life ... 6.05 *Years*

Northern Utilities, Inc.
New Hampshire
376.60 (367.50) MAINS - CATHODIC PROTECTION

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 18 *Survivor Curve: R5*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1991	1,069.53	18.00	59.42	3.23	191.81
1992	17,059.36	18.00	947.72	3.96	3,757.45
1993	17,144.61	18.00	952.46	4.78	4,554.19
1994	16,227.44	18.00	901.51	5.66	5,099.37
1995	23,991.12	18.00	1,332.81	6.58	8,764.88
1996	10,252.03	18.00	569.55	7.53	4,289.40
1997	11,779.22	18.00	654.39	8.51	5,568.81
1998	58,435.79	18.00	3,246.37	9.50	30,848.42
1999	29,488.21	18.00	1,638.20	10.50	17,202.06
2000	5,383.56	18.00	299.08	11.50	3,439.54
2001	2,582.15	18.00	143.45	12.50	1,793.18
2002	10,631.12	18.00	590.61	13.50	7,973.39
2003	30,482.95	18.00	1,693.46	14.50	24,555.83
2004	31,744.74	18.00	1,763.56	15.50	27,335.84
2005	17,549.14	18.00	974.93	16.50	16,086.74
2006	24,946.29	18.00	1,385.88	17.50	24,253.35
Total	308,767.26	18.00	17,153.39	10.83	185,714.25

Composite Average Remaining Life ... 10.8 Years

Northern Utilities, Inc.
New Hampshire
376.80 (367.10) MAINS - CAST IRON

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 62 *Survivor Curve:* S5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1939	44,883.68	62.00	723.93	4.22	3,053.56
1941	31,933.64	62.00	515.05	4.75	2,446.22
1945	3,762.08	62.00	60.68	6.07	368.38
1953	5,448.72	62.00	87.88	10.22	898.57
2003	1,685.27	62.00	27.18	58.50	1,590.13
Total	87,713.39	62.00	1,414.72	5.91	8,356.86

Composite Average Remaining Life ... 5.91 *Years*

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: ***30*** *Survivor Curve:* ***R3***

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1956	3,711.71	30.00	123.72	0.50	61.86
1970	3,806.03	30.00	126.87	3.63	460.85
1971	1,106.53	30.00	36.88	3.93	145.09
1973	2,969.09	30.00	98.97	4.61	456.09
1974	9,065.61	30.00	302.19	4.98	1,506.37
1978	11,927.96	30.00	397.60	6.80	2,702.85
1979	25,491.70	30.00	849.72	7.33	6,228.11
1980	5,454.31	30.00	181.81	7.89	1,435.18
1981	1,655.91	30.00	55.20	8.49	468.41
1985	17,703.88	30.00	590.13	11.12	6,563.93
1986	26,442.33	30.00	881.41	11.84	10,437.73
1988	20,534.24	30.00	684.47	13.34	9,130.16
1989	30,889.02	30.00	1,029.63	14.12	14,535.68
1990	122,239.45	30.00	4,074.64	14.91	60,763.70
1991	99,745.76	30.00	3,324.85	15.73	52,283.68
1992	38,665.95	30.00	1,288.86	16.56	21,337.77
1993	47,418.82	30.00	1,580.63	17.40	27,504.53
1994	112,232.69	30.00	3,741.08	18.26	68,319.40
1995	116,805.19	30.00	3,893.50	19.14	74,516.24
1996	193,131.71	30.00	6,437.72	20.03	128,938.44
1997	147,291.23	30.00	4,909.70	20.93	102,768.58
1998	110,779.24	30.00	3,692.64	21.85	80,677.05
1999	174,530.40	30.00	5,817.67	22.78	132,499.34
2000	257,845.24	30.00	8,594.83	23.71	203,809.28
2001	50,602.99	30.00	1,686.76	24.66	41,597.03
2002	15,958.64	30.00	531.95	25.62	13,626.97
2003	90,791.33	30.00	3,026.37	26.58	80,442.04

Northern Utilities, Inc.

New Hampshire

378.20 (369.00) PUMPING AND REG. STATION EQ.

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2006

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 30 *Survivor Curve: R3*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
2004	124,267.03	30.00	4,142.23	27.55	114,122.16
2005	90,181.40	30.00	3,006.04	28.53	85,753.19
Total	1,953,245.39	30.00	65,108.09	20.63	1,343,091.69

Composite Average Remaining Life ... 20.6 Years

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve: R3*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1934	82.71	47.00	1.76	1.68	2.95
1939	235.82	47.00	5.02	2.94	14.77
1940	22.32	47.00	0.47	3.19	1.52
1944	209.14	47.00	4.45	4.22	18.80
1945	449.18	47.00	9.56	4.49	42.87
1946	166.67	47.00	3.55	4.75	16.85
1947	1,279.67	47.00	27.23	5.02	136.72
1948	1,242.05	47.00	26.43	5.29	139.89
1949	940.92	47.00	20.02	5.58	111.71
1951	237.14	47.00	5.05	6.19	31.22
1952	1,000.62	47.00	21.29	6.51	138.60
1953	2,629.39	47.00	55.94	6.85	383.14
1954	1,279.65	47.00	27.23	7.20	196.12
1955	1,194.97	47.00	25.42	7.58	192.59
1956	3,198.67	47.00	68.06	7.97	542.10
1957	9,973.06	47.00	212.19	8.38	1,777.11
1958	7,951.87	47.00	169.19	8.80	1,489.56
1959	8,345.68	47.00	177.57	9.25	1,643.07
1960	7,224.12	47.00	153.70	9.72	1,494.38
1961	14,677.44	47.00	312.28	10.21	3,189.03
1962	23,628.48	47.00	502.73	10.72	5,390.06
1963	16,545.16	47.00	352.02	11.25	3,960.68
1964	29,974.11	47.00	637.74	11.80	7,527.57
1965	23,195.94	47.00	493.53	12.37	6,106.23
1966	21,044.96	47.00	447.76	12.96	5,803.26
1967	27,917.62	47.00	593.99	13.57	8,058.51

Northern Utilities, Inc.
New Hampshire
380.10 SERVICES - BARE STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve: R3*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	204,647.36	47.00	4,354.18	11.12	48,409.31

Composite Average Remaining Life ... 11.1 Years

Northern Utilities, Inc.
New Hampshire
380.20 SERVICES - COATED STEEL NOT WRAPPED
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 38 *Survivor Curve: L3*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1968	15,732.31	38.00	414.01	11.33	4,690.86
1969	6,769.19	38.00	178.14	11.50	2,048.49
1970	8,802.96	38.00	231.66	11.67	2,703.85
1971	20,161.77	38.00	530.58	11.86	6,290.84
1972	34,970.27	38.00	920.29	12.06	11,098.01
1973	39,169.64	38.00	1,030.80	12.28	12,661.39
1974	54,640.18	38.00	1,437.92	12.53	18,023.61
1975	30,770.53	38.00	809.76	12.82	10,379.54
1976	42,873.29	38.00	1,128.26	13.14	14,823.50
Total	253,890.14	38.00	6,681.43	12.38	82,720.09

Composite Average Remaining Life ... 12.3 Years

Northern Utilities, Inc.
New Hampshire
380.30 SERVICES - STEEL COATED & WRAPPED
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 38 *Survivor Curve: R1.5*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1977	9,335.25	38.00	245.66	16.70	4,102.63
1978	11,169.74	38.00	293.94	17.29	5,082.36
1979	54,754.30	38.00	1,440.88	17.89	25,781.59
1980	13,755.97	38.00	361.99	18.51	6,699.13
1981	30,132.08	38.00	792.94	19.13	15,170.73
1982	22,976.16	38.00	604.63	19.77	11,953.11
Total	142,123.50	38.00	3,740.03	18.39	68,789.55

Composite Average Remaining Life ... 18.3 Years

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1970	3,966.00	40.00	99.15	9.86	977.91
1971	11,065.43	40.00	276.64	10.43	2,883.98
1972	12,918.44	40.00	322.96	11.01	3,556.48
1973	13,966.36	40.00	349.16	11.62	4,056.62
1974	21,594.66	40.00	539.87	12.25	6,611.97
1975	14,346.70	40.00	358.67	12.89	4,624.71
1976	14,112.13	40.00	352.80	13.56	4,784.70
1977	70,348.78	40.00	1,758.72	14.25	25,054.15
1978	71,624.86	40.00	1,790.62	14.95	26,767.37
1979	319,202.09	40.00	7,980.05	15.67	125,015.80
1980	141,044.76	40.00	3,526.12	16.40	57,831.99
1981	178,978.26	40.00	4,474.45	17.15	76,733.61
1982	149,474.60	40.00	3,736.86	17.91	66,941.29
1983	142,428.17	40.00	3,560.70	18.69	66,551.61
1984	187,877.35	40.00	4,696.93	19.48	91,508.51
1985	341,211.93	40.00	8,530.29	20.29	173,047.88
1986	487,817.80	40.00	12,195.44	21.10	257,375.78
1987	665,352.52	40.00	16,633.80	21.93	364,834.18
1988	818,982.94	40.00	20,474.56	22.78	466,325.81
1989	822,528.43	40.00	20,563.20	23.63	485,885.61
1990	1,373,114.41	40.00	34,327.84	24.49	840,847.43
1991	1,331,985.80	40.00	33,299.62	25.37	844,817.64
1992	1,157,850.49	40.00	28,946.24	26.26	760,056.79
1993	855,770.82	40.00	21,394.26	27.15	580,939.02
1994	1,831,662.53	40.00	45,791.53	28.06	1,284,963.67
1995	919,616.07	40.00	22,990.39	28.98	666,183.80
1996	1,139,530.59	40.00	28,488.25	29.90	851,846.79

Northern Utilities, Inc.
New Hampshire
380.40 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1997	1,171,892.89	40.00	29,297.30	30.83	903,356.26
1998	1,082,154.35	40.00	27,053.84	31.77	859,633.92
1999	946,135.44	40.00	23,653.37	32.72	773,988.53
2000	936,245.47	40.00	23,406.12	33.68	788,236.00
2001	726,634.04	40.00	18,165.84	34.64	629,196.43
2002	1,137,613.32	40.00	28,440.31	35.60	1,012,530.93
2003	853,184.70	40.00	21,329.60	36.57	780,068.55
2004	1,017,037.72	40.00	25,425.93	37.55	954,669.05
2005	1,208,829.75	40.00	30,220.72	38.53	1,164,270.64
2006	1,139,416.28	40.00	28,485.39	39.51	1,125,396.57
Total	23,317,516.88	40.00	582,937.53	29.39	17,132,371.97

Composite Average Remaining Life ... 29.3 *Years*

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 30 *Survivor Curve:* R5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1975	19,604.20	30.00	653.48	2.39	1,562.41
1976	53,597.72	30.00	1,786.60	2.78	4,962.87
1977	90,768.28	30.00	3,025.63	3.22	9,752.40
1978	111,830.67	30.00	3,727.72	3.73	13,893.52
1979	146,035.82	30.00	4,867.90	4.29	20,890.07
1980	1,500.00	30.00	50.00	4.92	246.04
1981	267,176.76	30.00	8,905.96	5.61	49,924.21
1982	51,285.89	30.00	1,709.54	6.34	10,846.70
1983	50,588.50	30.00	1,686.30	7.14	12,032.80
1984	13,043.24	30.00	434.78	7.97	3,463.16
1985	96,499.57	30.00	3,216.68	8.83	28,403.31
1986	24,606.27	30.00	820.21	9.73	7,977.75
1987	76,664.32	30.00	2,555.50	10.65	27,207.99
1988	48,784.97	30.00	1,626.18	11.59	18,846.08
1989	94,748.62	30.00	3,158.31	12.55	39,639.65
1990	214,954.67	30.00	7,165.21	13.53	96,917.53
1991	193,803.31	30.00	6,460.16	14.51	93,748.30
1992	19,238.04	30.00	641.27	15.50	9,942.71
1993	30,733.71	30.00	1,024.46	16.50	16,905.04
1994	126,429.50	30.00	4,214.35	17.50	73,751.67
1995	84,769.61	30.00	2,825.67	18.50	52,274.52
1996	44,416.21	30.00	1,480.55	19.50	28,870.43
1997	136,809.65	30.00	4,560.35	20.50	93,486.28
1998	13,594.44	30.00	453.15	21.50	9,742.65
1999	64,015.52	30.00	2,133.87	22.50	48,011.52
2000	10,903.22	30.00	363.44	23.50	8,540.84
2001	34,537.54	30.00	1,151.26	24.50	28,205.61

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 30 *Survivor Curve: R5*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
2002	31,004.04	30.00	1,033.48	25.50	26,353.40
2003	44,940.50	30.00	1,498.03	26.50	39,697.40
2004	54,874.03	30.00	1,829.15	27.50	50,301.16
2005	180,263.73	30.00	6,008.83	28.50	171,250.48
Total	2,432,022.55	30.00	81,068.01	13.54	1,097,648.52

Composite Average Remaining Life ... 13.5 Years

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 32 *Survivor Curve: R4*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1975	11,847.40	32.00	370.23	4.93	1,825.52
1976	14,147.41	32.00	442.10	5.45	2,407.43
1977	14,353.71	32.00	448.55	6.01	2,696.08
1978	21,154.92	32.00	661.09	6.62	4,377.60
1979	52,090.16	32.00	1,627.81	7.27	11,834.03
1980	39,693.16	32.00	1,240.41	7.94	9,854.94
1981	45,691.70	32.00	1,427.86	8.64	12,338.75
1982	40,772.86	32.00	1,274.15	9.36	11,925.80
1983	34,439.17	32.00	1,076.22	10.10	10,873.38
1984	32,808.52	32.00	1,025.26	10.87	11,143.19
1985	49,790.75	32.00	1,555.96	11.66	18,138.66
1986	102,781.14	32.00	3,211.90	12.47	40,051.54
1987	113,561.02	32.00	3,548.77	13.30	47,214.07
1988	157,188.44	32.00	4,912.12	14.16	69,557.21
1989	241,895.26	32.00	7,559.20	15.04	113,662.24
1990	327,606.07	32.00	10,237.65	15.93	163,092.97
1991	340,875.43	32.00	10,652.32	16.84	179,416.88
1992	357,389.31	32.00	11,168.38	17.77	198,453.31
1993	366,563.52	32.00	11,455.07	18.71	214,308.93
1994	425,505.55	32.00	13,297.00	19.66	261,413.43
1995	359,183.25	32.00	11,224.44	20.62	231,451.67
1996	389,507.50	32.00	12,172.07	21.59	262,787.54
1997	454,996.44	32.00	14,218.59	22.57	320,847.40
1998	560,301.30	32.00	17,509.35	23.55	412,291.48
1999	568,345.43	32.00	17,760.73	24.53	435,729.01
2000	535,732.98	32.00	16,741.59	25.52	427,295.02
2001	471,499.12	32.00	14,734.29	26.52	390,685.90

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 32 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2002	618,283.22	32.00	19,321.28	27.51	531,528.26
2003	553,688.30	32.00	17,302.70	28.51	493,233.53
2004	515,468.03	32.00	16,108.32	29.50	475,252.07
2005	1,309,619.49	32.00	40,925.46	30.50	1,248,297.14
2006	69,475.16	32.00	2,171.09	31.50	68,390.52
Total	9,196,255.72	32.00	287,381.95	23.25	6,682,375.50

Composite Average Remaining Life ... 23.2 *Years*

Northern Utilities, Inc.
New Hampshire
383.00 GAS REGULATORS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 30 *Survivor Curve: R3*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1999	6,775.57	30.00	225.85	22.78	5,143.85
2000	3,744.90	30.00	124.83	23.71	2,960.09
2001	134,243.25	30.00	4,474.77	24.66	110,351.60
2002	350.30	30.00	11.68	25.62	299.12
2003	542.83	30.00	18.09	26.58	480.95
2004	39,538.37	30.00	1,317.94	27.55	36,310.55
Total	185,195.22	30.00	6,173.17	25.20	155,546.16

Composite Average Remaining Life ... 25.2 Years

Northern Utilities, Inc.
New Hampshire
386.12 (386.1 &.2) MISC. PROP ON CUST'S PREM. (WH & CB)

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 10 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1994	132,012.00	10.00	13,199.00	2.22	29,331.06
1995	36,637.21	10.00	3,663.11	2.59	9,479.99
1996	143,045.25	10.00	14,302.14	3.00	42,932.53
1997	78,551.57	10.00	7,853.85	3.47	27,237.63
1998	79,350.45	10.00	7,933.72	3.99	31,633.38
1999	82,649.77	10.00	8,263.60	4.56	37,658.35
2000	158,585.31	10.00	15,855.89	5.17	82,040.06
2001	94,028.25	10.00	9,401.26	5.83	54,841.22
2002	92,107.97	10.00	9,209.26	6.53	60,133.59
2003	51,285.88	10.00	5,127.73	7.26	37,214.23
2004	77,781.74	10.00	7,776.88	8.01	62,306.13
2005	63,111.46	10.00	6,310.10	8.79	55,466.19
2006	70,450.17	10.00	7,043.84	9.59	67,564.16
Total	1,159,597.03	10.00	115,940.40	5.16	597,838.53

Composite Average Remaining Life ... 5.16 Years

Northern Utilities, Inc.
New Hampshire
391.10 (391.10) OFFICE FURN & EQ-UNSPECIFIED
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: *11* *Survivor Curve:* *S3*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
1994	55,521.82	11.00	5,047.58	1.70	8,583.86
1995	287,709.13	11.00	26,156.13	2.02	52,743.87
1996	72,621.13	11.00	6,602.11	2.39	15,802.09
1997	26,919.23	11.00	2,447.27	2.85	6,962.87
1998	15,109.87	11.00	1,373.66	3.39	4,650.32
1999	30,754.11	11.00	2,795.91	4.03	11,255.81
2002	67,792.64	11.00	6,163.15	6.54	40,287.97
Total	556,427.93	11.00	50,585.82	2.77	140,286.79

Composite Average Remaining Life ... *2.77* *Years*

Northern Utilities, Inc.
New Hampshire
391.11 (391.10 & 20) OFFICE FURN & EQ-DATA HANDLING EQ
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: **10** *Survivor Curve:* **R4**

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
(1)	(2)	(3)	(4)	(5)	(6)
2004	7,565.50	10.00	756.55	7.51	5,683.57
Total	7,565.50	10.00	756.55	7.51	5,683.57

Composite Average Remaining Life ... 7.51 Years

Northern Utilities, Inc.
New Hampshire
391.12 (391.30) INFORMATION SYSTEMS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 8 *Survivor Curve: L4*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2002	17,724.71	8.00	2,215.62	3.61	7,988.50
2003	31,532.72	8.00	3,941.65	4.52	17,816.13
2004	5,250.00	8.00	656.26	5.50	3,609.74
2005	69,362.10	8.00	8,670.40	6.50	56,356.50
Total	123,869.53	8.00	15,483.94	5.54	85,770.87

Composite Average Remaining Life ... 5.54 Years

Northern Utilities, Inc.
New Hampshire
392.00 TRANSPORTATION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 9 *Survivor Curve:* L4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1995	27,479.29	9.00	3,053.44	1.38	4,226.56
1996	5,005.89	9.00	556.24	1.59	884.23
1999	2,290.91	9.00	254.56	2.27	577.39
2001	3,900.00	9.00	433.36	3.68	1,595.89
Total	38,676.09	9.00	4,297.60	1.69	7,284.07

Composite Average Remaining Life ... 1.69 *Years*

Northern Utilities, Inc.
New Hampshire
393.00 STORES EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 13 *Survivor Curve: L5*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	10,719.95	13.00	824.65	1.62	1,338.39
1994	20,800.00	13.00	1,600.07	1.88	3,012.65
Total	31,519.95	13.00	2,424.72	1.79	4,351.04

Composite Average Remaining Life ... 1.79 Years

Northern Utilities, Inc.
New Hampshire
394.10 (387.00) TOOLS, GARAGE AND SERVICE EQ
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 19 *Survivor Curve:* R5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1986	9,950.51	19.00	523.71	1.36	710.62
1987	20,330.96	19.00	1,070.04	1.70	1,822.55
1988	31,972.29	19.00	1,682.74	2.14	3,604.93
1989	21,026.41	19.00	1,106.64	2.68	2,963.08
1990	25,021.33	19.00	1,316.90	3.31	4,359.26
1991	25,000.14	19.00	1,315.78	4.03	5,307.84
1992	32,341.83	19.00	1,702.18	4.84	8,232.87
1993	7,504.82	19.00	394.99	5.70	2,250.36
1994	12,123.99	19.00	638.10	6.60	4,214.10
1995	43,537.37	19.00	2,291.42	7.55	17,294.06
1996	29,496.37	19.00	1,552.43	8.52	13,223.59
1997	22,755.60	19.00	1,197.65	9.51	11,383.89
1998	23,225.64	19.00	1,222.39	10.50	12,836.40
1999	50,066.79	19.00	2,635.07	11.50	30,303.98
2000	17,936.30	19.00	944.01	12.50	11,800.26
2001	14,705.49	19.00	773.97	13.50	10,448.68
2002	8,399.98	19.00	442.10	14.50	6,410.53
2003	15,486.21	19.00	815.06	15.50	12,633.51
2004	20,733.84	19.00	1,091.24	16.50	18,005.73
2005	6,573.99	19.00	346.00	17.50	6,055.00
Total	438,189.86	19.00	23,062.40	7.97	183,861.27

Composite Average Remaining Life ... 7.97 *Years*

Northern Utilities, Inc.
New Hampshire
394.30 (394.00) TOOLS, TOOLS AND OTHER
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: *18* *Survivor Curve:* *R5*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
1991	2,022.37	18.00	112.35	3.23	362.69
1993	4,904.40	18.00	272.46	4.78	1,302.77
1994	8,563.18	18.00	475.72	5.66	2,690.92
1995	12,585.76	18.00	699.19	6.58	4,598.06
1996	1,245.00	18.00	69.17	7.53	520.90
1998	2,825.00	18.00	156.94	9.50	1,491.33
2000	4,375.61	18.00	243.08	11.50	2,795.56
2001	3,468.65	18.00	192.70	12.50	2,408.81
2004	17,490.20	18.00	971.66	15.50	15,061.06
2005	1,141.10	18.00	63.39	16.50	1,046.01
2006	29,350.00	18.00	1,630.52	17.50	28,534.74
Total	87,971.27	18.00	4,887.19	12.44	60,812.85

Composite Average Remaining Life ... *12.4* *Years*

Northern Utilities, Inc.
New Hampshire
396.00 POWER OPERATED EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 15 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1990	52,482.50	15.00	3,498.81	1.64	5,724.32
1993	10,100.00	15.00	673.33	3.02	2,036.24
1999	2,289.00	15.00	152.60	7.68	1,172.16
2000	10,394.99	15.00	693.00	8.61	5,965.33
Total	75,266.49	15.00	5,017.74	2.97	14,898.05

Composite Average Remaining Life ... 2.97 *Years*

Northern Utilities, Inc.
New Hampshire
397.00 COMMUNICATION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 10 *Survivor Curve:* L3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	65,780.69	10.00	6,578.17	2.04	13,392.48
1994	17,379.00	10.00	1,737.93	2.54	4,416.79
1995	36,021.69	10.00	3,602.23	2.76	9,948.65
1996	8,397.50	10.00	839.76	2.94	2,471.38
1997	36,160.29	10.00	3,616.09	3.11	11,250.38
1999	33,240.42	10.00	3,324.09	3.67	12,201.64
2001	8,875.30	10.00	887.54	4.87	4,321.03
2003	21,404.62	10.00	2,140.50	6.58	14,076.81
2004	14,824.61	10.00	1,482.48	7.52	11,147.54
2005	46,484.65	10.00	4,648.54	8.50	39,517.72
2006	32,656.80	10.00	3,265.73	9.50	31,023.93
Total	321,225.57	10.00	32,123.06	4.79	153,768.36

Composite Average Remaining Life ... 4.79 *Years*

Northern Utilities, Inc.
New Hampshire
397.25 COMM EQUIP- METSCAN/TELEMETERING

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 10 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2004	5,312.00	10.00	531.19	7.59	4,033.03
2005	23,814.60	10.00	2,381.42	8.54	20,335.62
Total	29,126.60	10.00	2,912.61	8.37	24,368.65

Composite Average Remaining Life ... 8.37 *Years*

Northern Utilities, Inc.
New Hampshire
397.35 COMM EQUIP-ITRON EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2006
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 15 *Survivor Curve: R3*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
2003	1,690,443.22	15.00	112,695.50	11.62	1,309,736.40
2004	73,637.00	15.00	4,909.10	12.57	61,702.50
2005	111,228.94	15.00	7,415.22	13.53	100,347.01
Total	1,875,309.16	15.00	125,019.82	11.77	1,471,785.92

Composite Average Remaining Life ... 11.7 Years

Section 9

Northern Utilities, Inc.
New Hampshire
305.00 PRODUCTION PLANT STRUCTURES

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1979	2,782.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	5,101.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
305.00 PRODUCTION PLANT STRUCTURES
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1979 - 1981	2,782.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980 - 1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981 - 1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	5,101.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	5,101.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	5,101.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
305.00 PRODUCTION PLANT STRUCTURES

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 2006	7,883.00	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	0.0
Average Retirement Age (Yrs)	7.0
Years To ASL	-7.0
Inflation Factor At 2.75% to ASL	0.83

Gross Salvage
Linear Trend Analysis

1987-2006	**20 - Year Trend**	0.00%
1992-2006	**15 - Year Trend**	0.00%
1997-2006	**10 - Year Trend**	0.00%
2002-2006	**5 - Year Trend**	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
311.00 OTHER GAS GENERATING EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1981	51.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	7,250.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	711.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	2,000.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
311.00 OTHER GAS GENERATING EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1981 - 1983	51.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	7,250.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	7,961.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	7,961.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	711.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	2,000.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
311.00 OTHER GAS GENERATING EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1981 - 2006	10,012.00	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	0.0
Average Retirement Age (Yrs)	23.1
Years To ASL	-23.1
Inflation Factor At 2.75% to ASL	0.54

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.00%
1992-2006	15 - Year Trend	0.00%
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
320.00 OTHER PRODUCTION EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
2001	16,138.40	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	4,400.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
320.00 OTHER PRODUCTION EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
2001 - 2003	16,138.40	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	4,400.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2006	20,538.40	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	20.0
Average Retirement Age (Yrs)	11.9
Years To ASL	8.1
Inflation Factor At 2.75% to ASL	1.25

Gross Salvage
Linear Trend Analysis

1987-2006	**20 - Year Trend**	0.00%
1992-2006	**15 - Year Trend**	0.00%
1997-2006	**10 - Year Trend**	0.00%
2002-2006	**5 - Year Trend**	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1983 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1983	188.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	945.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	19,597.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1983 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1983 - 1985	188.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	945.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	20,542.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	20,542.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	19,597.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
321.00 LNG EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1983 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1983 - 2006	20,730.00	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	20.0
Average Retirement Age (Yrs)	15.0
Years To ASL	5.0
Inflation Factor At 2.75% to ASL	1.14

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.00%
1992-2006	15 - Year Trend	0.00%
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
2001	25,728.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
375.20 (366.00) CITY GATE-MEAS & REG STRUCTURES
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
2001 - 2003	25,728.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2006	25,728.50	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	80.0
Average Retirement Age (Yrs)	5.4
Years To ASL	74.6
Inflation Factor At 2.75% to ASL	7.57

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.00%
1992-2006	15 - Year Trend	0.00%
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
375.70 (390.00) OTHER DISTRIBUTION SYSTEM STRUCT.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1988 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1988	6,425.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
375.70 (390.00) OTHER DISTRIBUTION SYSTEM STRUCT.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1988 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1988 - 1990	6,425.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
375.70 (390.00) OTHER DISTRIBUTION SYSTEM STRUCT.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1988 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1988 - 2006	6,425.00	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	60.0
Average Retirement Age (Yrs)	15.1
Years To ASL	44.9
Inflation Factor At 2.75% to ASL	3.38

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.00%
1992-2006	15 - Year Trend	0.00%
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

Forcasted

Gross Salvage 0.00%
(Five Year Trend)

Cost Of Removal 0.00%

Net Salvage 0.00%

Northern Utilities, Inc.
New Hampshire
376.00 MAINS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1979	18,944.00	0.00	0.00%	4,546.00	24.00%	(4,546.00)	-24.00%
1980	14,699.00	0.00	0.00%	4,417.00	30.05%	(4,417.00)	-30.05%
1981	24,656.00	0.00	0.00%	2,501.00	10.14%	(2,501.00)	-10.14%
1982	7,575.00	0.00	0.00%	4,921.00	64.96%	(4,921.00)	-64.96%
1983	14,066.00	0.00	0.00%	7,838.00	55.72%	(7,838.00)	-55.72%
1984	22,047.00	0.00	0.00%	4,636.00	21.03%	(4,636.00)	-21.03%
1985	69,233.00	0.00	0.00%	9,332.00	13.48%	(9,332.00)	-13.48%
1986	23,455.00	0.00	0.00%	10,467.00	44.63%	(10,467.00)	-44.63%
1987	37,949.00	0.00	0.00%	9,103.00	23.99%	(9,103.00)	-23.99%
1988	36,759.00	0.00	0.00%	30,431.00	82.79%	(30,431.00)	-82.79%
1989	30,280.00	0.00	0.00%	16,110.00	53.20%	(16,110.00)	-53.20%
1990	95,912.00	0.00	0.00%	20,868.00	21.76%	(20,868.00)	-21.76%
1991	138,423.00	0.00	0.00%	37,704.00	27.24%	(37,704.00)	-27.24%
1992	73,462.00	0.00	0.00%	32,492.00	44.23%	(32,492.00)	-44.23%
1993	90,423.00	0.00	0.00%	1,286.00	1.42%	(1,286.00)	-1.42%
1994	222.00	0.00	0.00%	6,786.00	3056.76%	(6,786.00)	-3056.76%
1995	169,710.00	0.00	0.00%	23,804.00	14.03%	(23,804.00)	-14.03%
1996	132,018.00	0.00	0.00%	77,766.00	58.91%	(77,766.00)	-58.91%
1997	181,117.00	0.00	0.00%	5,495.00	3.03%	(5,495.00)	-3.03%
1998	65,642.00	0.00	0.00%	5,038.00	7.67%	(5,038.00)	-7.67%
1999	59,056.00	0.00	0.00%	5,603.00	9.49%	(5,603.00)	-9.49%
2000	304,768.00	0.00	0.00%	6,074.00	1.99%	(6,074.00)	-1.99%
2001	364,586.56	0.00	0.00%	25,964.88	7.12%	(25,964.88)	-7.12%
2002	60,332.35	0.00	0.00%	24,105.94	39.96%	(24,105.94)	-39.96%
2003	30,733.30	0.00	0.00%	10,986.52	35.75%	(10,986.52)	-35.75%
2004	193,556.45	0.00	0.00%	10,553.01	5.45%	(10,553.01)	-5.45%
2005	100,367.44	0.00	0.00%	664.88	0.66%	(664.88)	-0.66%
2006	38,297.67	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
376.00 MAINS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1979 - 1981	58,299.00	0.00	0.00%	11,464.00	19.66%	(11,464.00)	-19.66%
1980 - 1982	46,930.00	0.00	0.00%	11,839.00	25.23%	(11,839.00)	-25.23%
1981 - 1983	46,297.00	0.00	0.00%	15,260.00	32.96%	(15,260.00)	-32.96%
1982 - 1984	43,688.00	0.00	0.00%	17,395.00	39.82%	(17,395.00)	-39.82%
1983 - 1985	105,346.00	0.00	0.00%	21,806.00	20.70%	(21,806.00)	-20.70%
1984 - 1986	114,735.00	0.00	0.00%	24,435.00	21.30%	(24,435.00)	-21.30%
1985 - 1987	130,637.00	0.00	0.00%	28,902.00	22.12%	(28,902.00)	-22.12%
1986 - 1988	98,163.00	0.00	0.00%	50,001.00	50.94%	(50,001.00)	-50.94%
1987 - 1989	104,988.00	0.00	0.00%	55,644.00	53.00%	(55,644.00)	-53.00%
1988 - 1990	162,951.00	0.00	0.00%	67,409.00	41.37%	(67,409.00)	-41.37%
1989 - 1991	264,615.00	0.00	0.00%	74,682.00	28.22%	(74,682.00)	-28.22%
1990 - 1992	307,797.00	0.00	0.00%	91,064.00	29.59%	(91,064.00)	-29.59%
1991 - 1993	302,308.00	0.00	0.00%	71,482.00	23.65%	(71,482.00)	-23.65%
1992 - 1994	164,107.00	0.00	0.00%	40,564.00	24.72%	(40,564.00)	-24.72%
1993 - 1995	260,355.00	0.00	0.00%	31,876.00	12.24%	(31,876.00)	-12.24%
1994 - 1996	301,950.00	0.00	0.00%	108,356.00	35.89%	(108,356.00)	-35.89%
1995 - 1997	482,845.00	0.00	0.00%	107,065.00	22.17%	(107,065.00)	-22.17%
1996 - 1998	378,777.00	0.00	0.00%	88,299.00	23.31%	(88,299.00)	-23.31%
1997 - 1999	305,815.00	0.00	0.00%	16,136.00	5.28%	(16,136.00)	-5.28%
1998 - 2000	429,466.00	0.00	0.00%	16,715.00	3.89%	(16,715.00)	-3.89%
1999 - 2001	728,410.56	0.00	0.00%	37,641.88	5.17%	(37,641.88)	-5.17%
2000 - 2002	729,686.91	0.00	0.00%	56,144.82	7.69%	(56,144.82)	-7.69%
2001 - 2003	455,652.21	0.00	0.00%	61,057.34	13.40%	(61,057.34)	-13.40%
2002 - 2004	284,622.10	0.00	0.00%	45,645.47	16.04%	(45,645.47)	-16.04%
2003 - 2005	324,657.19	0.00	0.00%	22,204.41	6.84%	(22,204.41)	-6.84%
2004 - 2006	332,221.56	0.00	0.00%	11,217.89	3.38%	(11,217.89)	-3.38%

Northern Utilities, Inc.
New Hampshire
376.00 MAINS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 2006	2,398,289.77	0.00	0.00	399,493.23	16.66	(399,493.23)	-16.66

Trend Analysis (End Year) 2006

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	45.0
Average Retirement Age (Yrs)	0.0
Years To ASL	45.0
Inflation Factor At 2.75% to ASL	3.39

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.00%
1992-2006	15 - Year Trend	0.00%
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	56.48%
Net Salvage	-56.48%

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1979	12,453.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	301.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	2,191.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	64.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	4,296.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	3,000.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	22,339.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	90,981.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	10,141.00	3,850.00	37.96%	0.00	0.00%	3,850.00	37.96%
1994	20,304.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	8,433.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	45,820.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	3,634.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	1,334.63	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1979 - 1981	12,754.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980 - 1982	301.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981 - 1983	2,492.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	2,191.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	2,191.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	64.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	64.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	4,360.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	7,296.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	29,635.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	116,320.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	113,320.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	101,122.00	3,850.00	3.81%	0.00	0.00%	3,850.00	3.81%
1992 - 1994	30,445.00	3,850.00	12.65%	0.00	0.00%	3,850.00	12.65%
1993 - 1995	30,445.00	3,850.00	12.65%	0.00	0.00%	3,850.00	12.65%
1994 - 1996	20,304.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	8,433.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	54,253.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	57,887.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	49,454.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	4,968.63	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	1,334.63	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	1,334.63	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
378.20 (369.00) PUMPING AND REG. STATION EQ.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1979 - 2006	225,291.63	3,850.00	1.71	0.00	0.00	3,850.00	1.71

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	30.0
Average Retirement Age (Yrs)	9.3
Years To ASL	20.7
Inflation Factor At 2.75% to ASL	1.75

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.45%
1992-2006	15 - Year Trend	0.00% *
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
380.00 SERVICES

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1979	13,540.00	0.00	0.00%	16,177.00	119.48%	(16,177.00)	-119.48%
1980	20,867.00	0.00	0.00%	40,367.00	193.45%	(40,367.00)	-193.45%
1981	37,698.00	0.00	0.00%	12,910.00	34.25%	(12,910.00)	-34.25%
1982	14,959.00	0.00	0.00%	13,475.00	90.08%	(13,475.00)	-90.08%
1983	1,341.00	0.00	0.00%	21,809.00	1626.32%	(21,809.00)	-1626.32%
1984	1,299.00	0.00	0.00%	20,310.00	1563.51%	(20,310.00)	-1563.51%
1985	1,275.00	0.00	0.00%	18,936.00	1485.18%	(18,936.00)	-1485.18%
1986	3,135.00	0.00	0.00%	21,943.00	699.94%	(21,943.00)	-699.94%
1987	15,346.00	0.00	0.00%	26,569.00	173.13%	(26,569.00)	-173.13%
1988	21,744.00	0.00	0.00%	43,856.00	201.69%	(43,856.00)	-201.69%
1989	13,392.00	0.00	0.00%	19,671.00	146.89%	(19,671.00)	-146.89%
1990	21,702.00	0.00	0.00%	23,156.00	106.70%	(23,156.00)	-106.70%
1991	12,244.00	0.00	0.00%	21,317.00	174.10%	(21,317.00)	-174.10%
1992	22,384.00	0.00	0.00%	26,963.00	120.46%	(26,963.00)	-120.46%
1993	73,159.00	0.00	0.00%	58,855.00	80.45%	(58,855.00)	-80.45%
1994	20,606.00	0.00	0.00%	16,891.00	81.97%	(16,891.00)	-81.97%
1995	119,240.00	0.00	0.00%	20,453.00	17.15%	(20,453.00)	-17.15%
1996	42,959.00	0.00	0.00%	26,584.00	61.88%	(26,584.00)	-61.88%
1997	55,495.00	0.00	0.00%	32,471.00	58.51%	(32,471.00)	-58.51%
1998	44,181.00	0.00	0.00%	25,695.00	58.16%	(25,695.00)	-58.16%
1999	35,952.00	0.00	0.00%	21,330.00	59.33%	(21,330.00)	-59.33%
2000	46,696.00	0.00	0.00%	24,047.00	51.50%	(24,047.00)	-51.50%
2001	43,924.87	0.00	0.00%	28,361.92	64.57%	(28,361.92)	-64.57%
2002	34,896.06	0.00	0.00%	26,861.55	76.98%	(26,861.55)	-76.98%
2003	24,790.38	0.00	0.00%	38,206.89	154.12%	(38,206.89)	-154.12%
2004	28,090.80	0.00	0.00%	52,798.46	187.96%	(52,798.46)	-187.96%
2005	41,957.28	0.00	0.00%	44,479.17	106.01%	(44,479.17)	-106.01%
2006	14,037.27	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
380.00 SERVICES

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1979 - 1981	72,105.00	0.00	0.00%	69,454.00	96.32%	(69,454.00)	-96.32%
1980 - 1982	73,524.00	0.00	0.00%	66,752.00	90.79%	(66,752.00)	-90.79%
1981 - 1983	53,998.00	0.00	0.00%	48,194.00	89.25%	(48,194.00)	-89.25%
1982 - 1984	17,599.00	0.00	0.00%	55,594.00	315.89%	(55,594.00)	-315.89%
1983 - 1985	3,915.00	0.00	0.00%	61,055.00	1559.51%	(61,055.00)	-1559.51%
1984 - 1986	5,709.00	0.00	0.00%	61,189.00	1071.80%	(61,189.00)	-1071.80%
1985 - 1987	19,756.00	0.00	0.00%	67,448.00	341.41%	(67,448.00)	-341.41%
1986 - 1988	40,225.00	0.00	0.00%	92,368.00	229.63%	(92,368.00)	-229.63%
1987 - 1989	50,482.00	0.00	0.00%	90,096.00	178.47%	(90,096.00)	-178.47%
1988 - 1990	56,838.00	0.00	0.00%	86,683.00	152.51%	(86,683.00)	-152.51%
1989 - 1991	47,338.00	0.00	0.00%	64,144.00	135.50%	(64,144.00)	-135.50%
1990 - 1992	56,330.00	0.00	0.00%	71,436.00	126.82%	(71,436.00)	-126.82%
1991 - 1993	107,787.00	0.00	0.00%	107,135.00	99.40%	(107,135.00)	-99.40%
1992 - 1994	116,149.00	0.00	0.00%	102,709.00	88.43%	(102,709.00)	-88.43%
1993 - 1995	213,005.00	0.00	0.00%	96,199.00	45.16%	(96,199.00)	-45.16%
1994 - 1996	182,805.00	0.00	0.00%	63,928.00	34.97%	(63,928.00)	-34.97%
1995 - 1997	217,694.00	0.00	0.00%	79,508.00	36.52%	(79,508.00)	-36.52%
1996 - 1998	142,635.00	0.00	0.00%	84,750.00	59.42%	(84,750.00)	-59.42%
1997 - 1999	135,628.00	0.00	0.00%	79,496.00	58.61%	(79,496.00)	-58.61%
1998 - 2000	126,829.00	0.00	0.00%	71,072.00	56.04%	(71,072.00)	-56.04%
1999 - 2001	126,572.87	0.00	0.00%	73,738.92	58.26%	(73,738.92)	-58.26%
2000 - 2002	125,516.93	0.00	0.00%	79,270.47	63.16%	(79,270.47)	-63.16%
2001 - 2003	103,611.31	0.00	0.00%	93,430.36	90.17%	(93,430.36)	-90.17%
2002 - 2004	87,777.24	0.00	0.00%	117,866.90	134.28%	(117,866.90)	-134.28%
2003 - 2005	94,838.46	0.00	0.00%	135,484.52	142.86%	(135,484.52)	-142.86%
2004 - 2006	84,085.35	0.00	0.00%	97,277.63	115.69%	(97,277.63)	-115.69%

Northern Utilities, Inc.
New Hampshire
380.00 SERVICES

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 2006	826,910.66	0.00	0.00	744,492.99	90.03	(744,492.99)	-90.03

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	40.0
Average Retirement Age (Yrs)	16.9
Years To ASL	23.1
Inflation Factor At 2.75% to ASL	1.87

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.00%
1992-2006	15 - Year Trend	0.00%
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	168.65%
Net Salvage	-168.65%

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1979	8,760.00	1,563.00	17.84%	22.00	0.25%	1,541.00	17.59%
1980	15,246.00	0.00	0.00%	31.00	0.20%	(31.00)	-0.20%
1981	16,947.00	5,298.00	31.26%	225.00	1.33%	5,073.00	29.93%
1982	2,718.00	0.00	0.00%	1,884.00	69.32%	(1,884.00)	-69.32%
1983	5,815.00	1,671.00	28.74%	2,688.00	46.23%	(1,017.00)	-17.49%
1984	47,991.00	3,284.00	6.84%	1,719.00	3.58%	1,565.00	3.26%
1985	14,319.00	1,961.00	13.70%	1,456.00	10.17%	505.00	3.53%
1986	10,629.00	441.00	4.15%	1,887.00	17.75%	(1,446.00)	-13.60%
1987	36,982.00	6,133.00	16.58%	1,254.00	3.39%	4,879.00	13.19%
1988	7,606.00	257.00	3.38%	1,257.00	16.53%	(1,000.00)	-13.15%
1989	5,171.00	110.00	2.13%	166.00	3.21%	(56.00)	-1.08%
1990	8,451.00	70.00	0.83%	159.00	1.88%	(89.00)	-1.05%
1991	6,019.00	5.00	0.08%	58.00	0.96%	(53.00)	-0.88%
1992	7,556.00	12.00	0.16%	23.00	0.30%	(11.00)	-0.15%
1993	35,253.00	0.00	0.00%	308.00	0.87%	(308.00)	-0.87%
1994	11,515.00	0.00	0.00%	572.00	4.97%	(572.00)	-4.97%
1995	0.00	0.00	0.00%	8.00	0.00%	(8.00)	0.00%
1996	17,713.00	0.00	0.00%	6.00	0.03%	(6.00)	-0.03%
1997	12,117.00	0.00	0.00%	113.00	0.93%	(113.00)	-0.93%
1998	9,803.00	0.00	0.00%	256.00	2.61%	(256.00)	-2.61%
1999	14,612.00	0.00	0.00%	64.00	0.44%	(64.00)	-0.44%
2000	99,974.00	0.00	0.00%	645.00	0.65%	(645.00)	-0.65%
2001	21,250.14	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	12,883.80	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	36,592.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	3,841.50	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 1981	40,953.00	6,861.00	16.75%	278.00	0.68%	6,583.00	16.07%
1980 - 1982	34,911.00	5,298.00	15.18%	2,140.00	6.13%	3,158.00	9.05%
1981 - 1983	25,480.00	6,969.00	27.35%	4,797.00	18.83%	2,172.00	8.52%
1982 - 1984	56,524.00	4,955.00	8.77%	6,291.00	11.13%	(1,336.00)	-2.36%
1983 - 1985	68,125.00	6,916.00	10.15%	5,863.00	8.61%	1,053.00	1.55%
1984 - 1986	72,939.00	5,686.00	7.80%	5,062.00	6.94%	624.00	0.86%
1985 - 1987	61,930.00	8,535.00	13.78%	4,597.00	7.42%	3,938.00	6.36%
1986 - 1988	55,217.00	6,831.00	12.37%	4,398.00	7.96%	2,433.00	4.41%
1987 - 1989	49,759.00	6,500.00	13.06%	2,677.00	5.38%	3,823.00	7.68%
1988 - 1990	21,228.00	437.00	2.06%	1,582.00	7.45%	(1,145.00)	-5.39%
1989 - 1991	19,641.00	185.00	0.94%	383.00	1.95%	(198.00)	-1.01%
1990 - 1992	22,026.00	87.00	0.39%	240.00	1.09%	(153.00)	-0.69%
1991 - 1993	48,828.00	17.00	0.03%	389.00	0.80%	(372.00)	-0.76%
1992 - 1994	54,324.00	12.00	0.02%	903.00	1.66%	(891.00)	-1.64%
1993 - 1995	46,768.00	0.00	0.00%	888.00	1.90%	(888.00)	-1.90%
1994 - 1996	29,228.00	0.00	0.00%	586.00	2.00%	(586.00)	-2.00%
1995 - 1997	29,830.00	0.00	0.00%	127.00	0.43%	(127.00)	-0.43%
1996 - 1998	39,633.00	0.00	0.00%	375.00	0.95%	(375.00)	-0.95%
1997 - 1999	36,532.00	0.00	0.00%	433.00	1.19%	(433.00)	-1.19%
1998 - 2000	124,389.00	0.00	0.00%	965.00	0.78%	(965.00)	-0.78%
1999 - 2001	135,836.14	0.00	0.00%	709.00	0.52%	(709.00)	-0.52%
2000 - 2002	134,107.94	0.00	0.00%	645.00	0.48%	(645.00)	-0.48%
2001 - 2003	34,133.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	49,476.30	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	36,592.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	40,434.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2006

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1979 - 2006	469,764.94	20,805.00	4.43	14,801.00	3.15	6,004.00	1.28

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	30.0
Average Retirement Age (Yrs)	10.7
Years To ASL	19.3
Inflation Factor At 2.75% to ASL	1.69

Gross Salvage
Linear Trend Analysis

1987-2006	**20 - Year Trend**	0.00% *
1992-2006	**15 - Year Trend**	0.00% *
1997-2006	**10 - Year Trend**	0.00%
2002-2006	**5 - Year Trend**	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%—Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	5.31%
Net Salvage	-5.31%

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
2001	14,266.52	0.00	0.00%	3,118.18	21.86%	(3,118.18)	-21.86%
2002	15,855.02	0.00	0.00%	2,104.57	13.27%	(2,104.57)	-13.27%
2003	0.00	0.00	0.00%	1,803.66	0.00%	(1,803.66)	0.00%
2004	47,560.41	0.00	0.00%	2,584.54	5.43%	(2,584.54)	-5.43%
2005	0.00	0.00	0.00%	1,006.00	0.00%	(1,006.00)	0.00%
2006	12,273.70	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
382.00 METER INSTALLATIONS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
2001 - 2003	30,121.54	0.00	0.00%	7,026.41	23.33%	(7,026.41)	-23.33%
2002 - 2004	63,415.43	0.00	0.00%	6,492.77	10.24%	(6,492.77)	-10.24%
2003 - 2005	47,560.41	0.00	0.00%	5,394.20	11.34%	(5,394.20)	-11.34%
2004 - 2006	59,834.11	0.00	0.00%	3,590.54	6.00%	(3,590.54)	-6.00%
2001 - 2006	89,955.65	0.00	0.00	10,616.95	11.80	(10,616.95)	-11.80

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	32.0
Average Retirement Age (Yrs)	5.2
Years To ASL	26.8
Inflation Factor At 2.75% to ASL	2.07

Gross Salvage
Linear Trend Analysis

1987-2006	**20 - Year Trend**	0.00%
1992-2006	**15 - Year Trend**	0.00%
1997-2006	**10 - Year Trend**	0.00%
2002-2006	**5 - Year Trend**	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	24.40%
Net Salvage	-24.40%

Northern Utilities, Inc.
New Hampshire
386.00 MISC PROP ON CUSTOMERS' PREM.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2005

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1979	4,197.00	51.00	1.22%	106.00	2.53%	(55.00)	-1.31%
1980	3,591.00	0.00	0.00%	17.00	0.47%	(17.00)	-0.47%
1981	7,273.00	2,093.00	28.78%	0.00	0.00%	2,093.00	28.78%
1982	56,358.00	3,027.00	5.37%	0.00	0.00%	3,027.00	5.37%
1983	14,417.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	6,696.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	7,417.00	956.00	12.89%	0.00	0.00%	956.00	12.89%
1986	6,438.00	1,539.00	23.90%	0.00	0.00%	1,539.00	23.90%
1987	11,145.00	718.00	6.44%	0.00	0.00%	718.00	6.44%
1988	7,558.00	3,406.00	45.06%	0.00	0.00%	3,406.00	45.06%
1989	16,442.00	3,325.00	20.22%	0.00	0.00%	3,325.00	20.22%
1990	8,271.00	3,287.00	39.74%	0.00	0.00%	3,287.00	39.74%
1991	15,610.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	53,428.00	8,209.00	15.36%	0.00	0.00%	8,209.00	15.36%
1993	60,011.00	14,548.00	24.24%	546.00	0.91%	14,002.00	23.33%
1994	24,648.00	11,121.00	45.12%	84.00	0.34%	11,037.00	44.78%
1995	138,647.00	15,267.00	11.01%	0.00	0.00%	15,267.00	11.01%
1996	48,413.00	16,131.00	33.32%	0.00	0.00%	16,131.00	33.32%
1997	108,508.00	21,973.00	20.25%	0.00	0.00%	21,973.00	20.25%
1998	132,621.00	25,725.00	19.40%	0.00	0.00%	25,725.00	19.40%
1999	122,110.00	16,120.00	13.20%	0.00	0.00%	16,120.00	13.20%
2000	90,067.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	117,162.71	11,428.66	9.75%	0.00	0.00%	11,428.66	9.75%
2002	423,240.10	6,182.21	1.46%	0.00	0.00%	6,182.21	1.46%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	814,410.91	4,992.73	0.61%	0.00	0.00%	4,992.73	0.61%
2005	247,074.14	10,237.20	4.14%	0.00	0.00%	10,237.20	4.14%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
386.00 MISC PROP ON CUSTOMERS' PREM.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2005

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1979 - 1981	15,061.00	2,144.00	14.24%	123.00	0.82%	2,021.00	13.42%
1980 - 1982	67,222.00	5,120.00	7.62%	17.00	0.03%	5,103.00	7.59%
1981 - 1983	78,048.00	5,120.00	6.56%	0.00	0.00%	5,120.00	6.56%
1982 - 1984	77,471.00	3,027.00	3.91%	0.00	0.00%	3,027.00	3.91%
1983 - 1985	28,530.00	956.00	3.35%	0.00	0.00%	956.00	3.35%
1984 - 1986	20,551.00	2,495.00	12.14%	0.00	0.00%	2,495.00	12.14%
1985 - 1987	25,000.00	3,213.00	12.85%	0.00	0.00%	3,213.00	12.85%
1986 - 1988	25,141.00	5,663.00	22.52%	0.00	0.00%	5,663.00	22.52%
1987 - 1989	35,145.00	7,449.00	21.20%	0.00	0.00%	7,449.00	21.20%
1988 - 1990	32,271.00	10,018.00	31.04%	0.00	0.00%	10,018.00	31.04%
1989 - 1991	40,323.00	6,612.00	16.40%	0.00	0.00%	6,612.00	16.40%
1990 - 1992	77,309.00	11,496.00	14.87%	0.00	0.00%	11,496.00	14.87%
1991 - 1993	129,049.00	22,757.00	17.63%	546.00	0.42%	22,211.00	17.21%
1992 - 1994	138,087.00	33,878.00	24.53%	630.00	0.46%	33,248.00	24.08%
1993 - 1995	223,306.00	40,936.00	18.33%	630.00	0.28%	40,306.00	18.05%
1994 - 1996	211,708.00	42,519.00	20.08%	84.00	0.04%	42,435.00	20.04%
1995 - 1997	295,568.00	53,371.00	18.06%	0.00	0.00%	53,371.00	18.06%
1996 - 1998	289,542.00	63,829.00	22.04%	0.00	0.00%	63,829.00	22.04%
1997 - 1999	363,239.00	63,818.00	17.57%	0.00	0.00%	63,818.00	17.57%
1998 - 2000	344,798.00	41,845.00	12.14%	0.00	0.00%	41,845.00	12.14%
1999 - 2001	329,339.71	27,548.66	8.36%	0.00	0.00%	27,548.66	8.36%
2000 - 2002	630,469.81	17,610.87	2.79%	0.00	0.00%	17,610.87	2.79%
2001 - 2003	540,402.81	17,610.87	3.26%	0.00	0.00%	17,610.87	3.26%
2002 - 2004	1,237,651.01	11,174.94	0.90%	0.00	0.00%	11,174.94	0.90%
2003 - 2005	1,061,485.05	15,229.93	1.43%	0.00	0.00%	15,229.93	1.43%
2004 - 2006	1,061,485.05	15,229.93	1.43%	0.00	0.00%	15,229.93	1.43%

Northern Utilities, Inc.
New Hampshire
386.00 MISC PROP ON CUSTOMERS' PREM.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2005

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 2005	2,545,753.86	180,336.80	7.08	753.00	0.03	179,583.80	7.05

Trend Analysis (End Year) **2005**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	10.0
Average Retirement Age (Yrs)	0.0
Years To ASL	10.0
Inflation Factor At 2.75% to ASL	1.31

Gross Salvage
Linear Trend Analysis

1986-2005	20 - Year Trend	3.56%
1991-2005	15 - Year Trend	0.96%
1996-2005	10 - Year Trend	0.00% *
2001-2005	5 - Year Trend	1.06%

***Forecasted Gross Salvage Calculates To Less Than 0.00%—Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	1.06%
Cost Of Removal	0.04%
Net Salvage	1.02%

Northern Utilities, Inc.
New Hampshire
391.00 OFFICE FURNITURE & EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2004

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1979	165.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	2,879.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	9,920.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	10,342.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	397.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	745.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	591.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	4,187.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	36,962.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	446.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	49,888.00	4,024.00	8.07%	0.00	0.00%	4,024.00	8.07%
1992	12,292.00	1,000.00	8.14%	0.00	0.00%	1,000.00	8.14%
1993	1,780.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	1,690.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	19,027.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	46,877.00	12,000.00	25.60%	0.00	0.00%	12,000.00	25.60%
1999	153,307.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	295,135.00	11,848.00	4.01%	0.00	0.00%	11,848.00	4.01%
2001	261,970.43	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	32,097.45	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	221,152.58	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
391.00 OFFICE FURNITURE & EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2004

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 1981	3,044.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980 - 1982	12,799.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981 - 1983	23,141.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	20,659.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	11,484.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	1,733.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	5,523.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	4,778.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	41,149.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	37,408.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	87,296.00	4,024.00	4.61%	0.00	0.00%	4,024.00	4.61%
1990 - 1992	62,626.00	5,024.00	8.02%	0.00	0.00%	5,024.00	8.02%
1991 - 1993	63,960.00	5,024.00	7.85%	0.00	0.00%	5,024.00	7.85%
1992 - 1994	15,762.00	1,000.00	6.34%	0.00	0.00%	1,000.00	6.34%
1993 - 1995	3,470.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	1,690.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	19,027.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	65,904.00	12,000.00	18.21%	0.00	0.00%	12,000.00	18.21%
1997 - 1999	219,211.00	12,000.00	5.47%	0.00	0.00%	12,000.00	5.47%
1998 - 2000	495,319.00	23,848.00	4.81%	0.00	0.00%	23,848.00	4.81%
1999 - 2001	710,412.43	11,848.00	1.67%	0.00	0.00%	11,848.00	1.67%
2000 - 2002	589,202.88	11,848.00	2.01%	0.00	0.00%	11,848.00	2.01%
2001 - 2003	294,067.88	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	253,250.03	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	221,152.58	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	221,152.58	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
391.00 OFFICE FURNITURE & EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2004

Year	Orginal Cost Of Retirements	Gross Salvage Amount	%	Cost of Removal Amount	%	Net Salvage Amount	%
Three - Year Rolling Bands							
1979 - 2004	1,161,850.46	28,872.00	2.49	0.00	0.00	28,872.00	2.49

Trend Analysis (End Year) **2004**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	11.0
Average Retirement Age (Yrs)	12.9
Years To ASL	-1.9
Inflation Factor At 2.75% to ASL	0.95

Gross Salvage
Linear Trend Analysis

1985-2004	20 - Year Trend	2.59%
1990-2004	15 - Year Trend	0.65%
1995-2004	10 - Year Trend	0.00% *
2000-2004	5 - Year Trend	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
392.00 TRANSPORTATION EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1981	1,678.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	4,190.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	3,014.00	2,950.00	97.88%	0.00	0.00%	2,950.00	97.88%
1984	4,591.00	2,684.00	58.46%	0.00	0.00%	2,684.00	58.46%
1985	6,750.00	5,392.00	79.88%	0.00	0.00%	5,392.00	79.88%
1986	1,450.00	800.00	55.17%	0.00	0.00%	800.00	55.17%
1987	12,280.00	2,211.00	18.00%	0.00	0.00%	2,211.00	18.00%
1988	0.00	4,800.00	0.00%	0.00	0.00%	4,800.00	0.00%
1989	15,454.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	462.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	5,880.00	200.00	3.40%	0.00	0.00%	200.00	3.40%
1992	59,771.00	21,470.00	35.92%	0.00	0.00%	21,470.00	35.92%
1993	19,319.00	6,892.00	35.67%	0.00	0.00%	6,892.00	35.67%
1994	8,295.00	5,730.00	69.08%	0.00	0.00%	5,730.00	69.08%
1995	0.00	14,494.00	0.00%	0.00	0.00%	14,494.00	0.00%
1996	0.00	4,313.00	0.00%	0.00	0.00%	4,313.00	0.00%
1997	40,905.00	4,570.00	11.17%	0.00	0.00%	4,570.00	11.17%
1998	139,712.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	139,712.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	57,378.64	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	800.00	0.00%	0.00	0.00%	800.00	0.00%
2003	127,038.83	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	80,519.15	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
392.00 TRANSPORTATION EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1981 - 1983	8,882.00	2,950.00	33.21%	0.00	0.00%	2,950.00	33.21%
1982 - 1984	11,795.00	5,634.00	47.77%	0.00	0.00%	5,634.00	47.77%
1983 - 1985	14,355.00	11,026.00	76.81%	0.00	0.00%	11,026.00	76.81%
1984 - 1986	12,791.00	8,876.00	69.39%	0.00	0.00%	8,876.00	69.39%
1985 - 1987	20,480.00	8,403.00	41.03%	0.00	0.00%	8,403.00	41.03%
1986 - 1988	13,730.00	7,811.00	56.89%	0.00	0.00%	7,811.00	56.89%
1987 - 1989	27,734.00	7,011.00	25.28%	0.00	0.00%	7,011.00	25.28%
1988 - 1990	15,916.00	4,800.00	30.16%	0.00	0.00%	4,800.00	30.16%
1989 - 1991	21,796.00	200.00	0.92%	0.00	0.00%	200.00	0.92%
1990 - 1992	66,113.00	21,670.00	32.78%	0.00	0.00%	21,670.00	32.78%
1991 - 1993	84,970.00	28,562.00	33.61%	0.00	0.00%	28,562.00	33.61%
1992 - 1994	87,385.00	34,092.00	39.01%	0.00	0.00%	34,092.00	39.01%
1993 - 1995	27,614.00	27,116.00	98.20%	0.00	0.00%	27,116.00	98.20%
1994 - 1996	8,295.00	24,537.00	295.80%	0.00	0.00%	24,537.00	295.80%
1995 - 1997	40,905.00	23,377.00	57.15%	0.00	0.00%	23,377.00	57.15%
1996 - 1998	180,617.00	8,883.00	4.92%	0.00	0.00%	8,883.00	4.92%
1997 - 1999	180,617.00	4,570.00	2.53%	0.00	0.00%	4,570.00	2.53%
1998 - 2000	279,424.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	197,090.64	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	197,090.64	800.00	0.41%	0.00	0.00%	800.00	0.41%
2001 - 2003	184,417.47	800.00	0.43%	0.00	0.00%	800.00	0.43%
2002 - 2004	207,557.98	800.00	0.39%	0.00	0.00%	800.00	0.39%
2003 - 2005	207,557.98	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	80,519.15	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
392.00 TRANSPORTATION EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1981 - 2006	728,399.62	77,306.00	10.61	0.00	0.00	77,306.00	10.61

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	9.0
Average Retirement Age (Yrs)	7.1
Years To ASL	1.9
Inflation Factor At 2.75% to ASL	1.05

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	6.42%
1992-2006	15 - Year Trend	0.00% *
1997-2006	10 - Year Trend	0.00% *
2002-2006	5 - Year Trend	0.00% *

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00% *
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
393.00 STORES EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1981	608.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	1,291.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	4,368.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	3,664.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	44,688.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	560.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	5,180.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
393.00 STORES EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1981 - 1983	608.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	1,291.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	1,291.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	1,291.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	4,368.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	4,368.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	4,368.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	3,664.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	3,664.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	48,352.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	45,248.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	45,248.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	560.50	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	5,180.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	5,180.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	5,180.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
393.00 STORES EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1981 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1981 - 2006	60,359.50	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	13.0
Average Retirement Age (Yrs)	8.8
Years To ASL	4.2
Inflation Factor At 2.75% to ASL	1.12

Gross Salvage
Linear Trend Analysis

1987-2006	20 - Year Trend	0.00%
1992-2006	15 - Year Trend	0.00%
1997-2006	10 - Year Trend	0.00%
2002-2006	5 - Year Trend	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
394.00 TOOLS, GARAGE AND WORK EQUIP

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2004

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1979	5,432.00	889.00	16.37%	0.00	0.00%	889.00	16.37%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	8,083.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	5,207.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	12,533.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	4,450.00	1,404.00	31.55%	0.00	0.00%	1,404.00	31.55%
1985	2,372.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	850.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	27,982.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	8,295.00	1,325.00	15.97%	0.00	0.00%	1,325.00	15.97%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	1,387.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	18,546.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
394.00 TOOLS, GARAGE AND WORK EQUIP
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2004

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 1981	13,515.00	889.00	6.58%	0.00	0.00%	889.00	6.58%
1980 - 1982	13,290.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981 - 1983	25,823.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	22,190.00	1,404.00	6.33%	0.00	0.00%	1,404.00	6.33%
1983 - 1985	19,355.00	1,404.00	7.25%	0.00	0.00%	1,404.00	7.25%
1984 - 1986	6,822.00	1,404.00	20.58%	0.00	0.00%	1,404.00	20.58%
1985 - 1987	3,222.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	850.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	28,832.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	27,982.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	27,982.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	8,295.00	1,325.00	15.97%	0.00	0.00%	1,325.00	15.97%
1993 - 1995	8,295.00	1,325.00	15.97%	0.00	0.00%	1,325.00	15.97%
1994 - 1996	8,295.00	1,325.00	15.97%	0.00	0.00%	1,325.00	15.97%
1995 - 1997	1,387.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	1,387.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	1,387.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	18,546.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	18,546.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	18,546.36	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
394.00 TOOLS, GARAGE AND WORK EQUIP
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1979 - 2004

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1979 - 2004	95,137.36	3,618.00	3.80	0.00	0.00	3,618.00	3.80

Trend Analysis (End Year) **2004**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	18.0
Average Retirement Age (Yrs)	0.0
Years To ASL	18.0
Inflation Factor At 2.75% to ASL	1.63

Gross Salvage
Linear Trend Analysis

1985-2004	20 - Year Trend	1.48%
1990-2004	15 - Year Trend	0.00% *
1995-2004	10 - Year Trend	0.00%
2000-2004	5 - Year Trend	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
396.00 POWER OPERATED EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1982 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1982	1,628.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	9,205.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	15,598.00	5,000.00	32.06%	0.00	0.00%	5,000.00	32.06%
1986	20,743.00	10,000.00	48.21%	0.00	0.00%	10,000.00	48.21%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	26,511.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	462.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	700.00	0.00%	0.00	0.00%	700.00	0.00%
1992	27,900.00	20,576.00	73.75%	0.00	0.00%	20,576.00	73.75%
1993	13,810.00	5,850.00	42.36%	0.00	0.00%	5,850.00	42.36%
1994	5,503.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	43,171.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	7,050.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	12,282.40	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	33,140.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	9,780.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	70,040.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
396.00 POWER OPERATED EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1982 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1982 - 1984	10,833.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	24,803.00	5,000.00	20.16%	0.00	0.00%	5,000.00	20.16%
1984 - 1986	36,341.00	15,000.00	41.28%	0.00	0.00%	15,000.00	41.28%
1985 - 1987	36,341.00	15,000.00	41.28%	0.00	0.00%	15,000.00	41.28%
1986 - 1988	20,743.00	10,000.00	48.21%	0.00	0.00%	10,000.00	48.21%
1987 - 1989	26,511.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	26,973.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	26,973.00	700.00	2.60%	0.00	0.00%	700.00	2.60%
1990 - 1992	28,362.00	21,276.00	75.02%	0.00	0.00%	21,276.00	75.02%
1991 - 1993	41,710.00	27,126.00	65.03%	0.00	0.00%	27,126.00	65.03%
1992 - 1994	47,213.00	26,426.00	55.97%	0.00	0.00%	26,426.00	55.97%
1993 - 1995	19,313.00	5,850.00	30.29%	0.00	0.00%	5,850.00	30.29%
1994 - 1996	48,674.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	50,221.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	50,221.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	7,050.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	12,282.40	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	45,422.40	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	55,202.40	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	112,960.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	79,820.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	70,040.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
396.00 POWER OPERATED EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1982 - 2006

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1982 - 2006	296,823.40	42,126.00	14.19	0.00	0.00	42,126.00	14.19

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	15.0
Average Retirement Age (Yrs)	13.1
Years To ASL	1.9
Inflation Factor At 2.75% to ASL	1.05

Gross Salvage
Linear Trend Analysis

1987-2006	**20 - Year Trend**	0.00% *
1992-2006	**15 - Year Trend**	0.00% *
1997-2006	**10 - Year Trend**	0.00%
2002-2006	**5 - Year Trend**	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
New Hampshire
397.00 COMMUNICATION EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1984 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1984	1,508.00	1,584.00	105.04%	0.00	0.00%	1,584.00	105.04%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	3,279.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	1,647.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	4,844.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	21,578.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	21,235.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	15,616.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	11,448.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	87,458.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	182,016.53	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	105,379.54	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	116,884.59	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
397.00 COMMUNICATION EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1984 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1984 - 1986	1,508.00	1,584.00	105.04%	0.00	0.00%	1,584.00	105.04%
1985 - 1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	3,279.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	4,926.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	4,926.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	6,491.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	4,844.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	4,844.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	21,578.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	42,813.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	58,429.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	48,299.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	114,522.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	98,906.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	269,474.53	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	182,016.53	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	182,016.53	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	105,379.54	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	222,264.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	222,264.13	0.00	0.00%	0.00	0.00%	0.00	0.00%

Northern Utilities, Inc.
New Hampshire
397.00 COMMUNICATION EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1984 - 2006

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1984 - 2006	572,893.66	1,584.00	0.28	0.00	0.00	1,584.00	0.28

Trend Analysis (End Year) **2006**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	15.0
Average Retirement Age (Yrs)	6.3
Years To ASL	8.7
Inflation Factor At 2.75% to ASL	1.27

Gross Salvage
Linear Trend Analysis

1987-2006	**20 - Year Trend**	0.00%
1992-2006	**15 - Year Trend**	0.00%
1997-2006	**10 - Year Trend**	0.00%
2002-2006	**5 - Year Trend**	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(14) List of officers and directors of the utility and their compensation for the last two years.

Response:

Northern Utilities, Inc. is a wholly owned subsidiary of Unitil Corporation. The officers and directors of Northern Utilities, Inc. ("Northern") are also officers and directors of Unitil Corporation, and may be officers of other Unitil Corporation subsidiaries.

The following table reflects the annual compensation paid to individuals who serve on the Board of Directors of Northern.

	2009		**2010**	
	Compensation	**Common Stock**	**Compensation**	**Common Stock**
William D. Adams	400	--	400	--
Robert V. Antonucci	400	--	400	--
David P. Brownell	400	--	500	--
Michael J. Dalton	400	--	500	--
Albert H. Elfner, III	400	--	500	--
Edward F. Godfrey	400	--	500	--
Michael B. Green	400	--	500	--
Eben S. Moulton	400	--	500	--
M. Brian O'Shaughnessy	400	--	400	--
Robert G. Schoenberger [1]	N/A	--	N/A	--
Charles H. Tenney III [2]	--	--	--	--
Sarah P. Voll	400	--	500	--

(1) Employee Directors are not compensated for Board service.
(2) Charles H. Tenney III passed away on March 12, 2009, prior to any Board meetings being held.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

The following table lists the total annual compensation for the officers of Northern for the past two years. All officers' compensation is allocated to Unitil Corporation's subsidiaries through the Unitil Service Corp. billing system.

	2009			2010		
	Base Salary	**Incentive Pay**	**Restricted Stock**	**Base Salary**	**Incentive Pay**	**Restricted Stock**
Robert G. Schoenberger, President	456,601	294,796	122,366	456,601	196,338	168,849
Thomas P. Meissner, Jr., Senior Vice President	224,564	101,000	41,445	224,564	67,594	54,743
George R. Gantz Senior Vice President	200,630	77,532	48,129	200,630	51,763	22,057
Mark H. Collin, Treasurer	221,942	99,820	37,505	221,942	66,805	54,743
Laurence M. Brock, Controller	160,165	41,363	39,512	160,165	38,548	8,280
Sandra L. Whitney, Secretary	81,250	5,187	--	81,250	3,494	1,618
David K. Foote, [1] Sr. Vice President	--	19,586	--	--	--	--
Charles J. Kershaw, Jr., [2] Assistant Treasurer	--	2,379	--	--	--	--

(1) David K. Foote retired in July, 2008, but received incentive pay in 2009 for 2008 financial results.

(2) Charles J. Kershaw, Jr. retired in March, 2008, but received incentive pay in 2009 for 2008 financial results.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(15) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;

b. Owned by the spouse or minor child of an officer or director; or

c. Controlled by the officer or director directly or indirectly.

Response:

For Northern Utilities, Inc. (Northern), the voting stock consists solely of common stock. The 100 outstanding shares of common stock of Northern are owned by Unitil Corporation. Therefore, the following responses are provided:

a. Owned by an officer or director individually – 0 shares

b. Owned by the spouse or minor child of an officer or director – 0 shares

c. Controlled by the officer or director directly or indirectly – 0 shares

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(16) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $100,000 in annual gross revenues, a list of all payments in excess of $1,000;
b. For utilities with annual gross revenues of $100,000 or between $100,000 and $10,000,000, a list of all payments in excess of $10,000;
c. For utilities with annual gross revenues of $10,000,000 or between $10,000,000 and $100,000,000, a list of all payments in excess of $50,000;
d. For utilities with annual gross revenues of $100,000,000 or in excess of $100,000,000, a list of all payments in excess of $100,000; and
e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular entity shall be on a cumulative basis, indicating the number of items comprising the total amount of expenditure.

Response:

Please see attached schedule of contractual payments in excess of $100,000 paid by Northern Utilities, Inc. during the test year.

Name	Description		Amount	Quanity of Invoices	Division
ADP	Payroll Services	$	5,502,280.52	80	NH & ME
AECOM	Professional Services	$	201,849.58	36	NH
AMERICAN UNITED LIFE INSURANCE	Life Insurance	$	207,300.00	3	NH & ME
CITY OF DOVER	Property Taxes & Police Detail	$	258,949.56	33	NH
CITY OF PORTSMOUTH	Property Taxes & Police Detail	$	278,820.33	25	NH
City Of Rochester	Property Taxes & Police Detail	$	157,309.29	4	NH
City Of Somersworth	Property Taxes & Police Detail	$	113,732.00	3	NH
CONCENTRIC ENERGY ADVISORS	Energy Advisors	$	423,007.40	19	NH & ME
ELSTER AMERICAN METER	Materials & Supplies	$	101,744.93	10	NH
Energy Federation, Inc	Rebates	$	181,512.99	13	NH
GEORG FISCHER CENTRAL	Materials & Supplies	$	104,893.23	63	NH
Hall Estill	Legal Expenses	$	167,277.37	9	NH & ME
ITRON INC	Materials & Supplies		100,635.79	4	NH
KUBRA DATA TRANSFER LTD	Customer Bill Generation & Postage	$	182,441.94	27	NH
METLIFE INSURANCE	INSURANCE	$	3,159,500.00	10	NH & ME
MULCARE ENGINEERING	Materials & Supplies	$	113,353.42	59	NH
MUTUAL OF OMAHA INSURANCE COMPANY	INSURANCE	$	579,000.00	2	NH & ME
NEW ENGLAND LIFE INSURANCE CO	INSURANCE	$	695,000.00	2	NH & ME
New England Utility Contractor	Labor & Equipment	$	9,799,006.72	2129	NH
PERFORMANCE PIPE	Materials & Supplies	$	179,993.12	28	NH
PIERCE ATWOOD LLP	Legal Expenses	$	801,727.33	51	NH & ME
PROCESS PIPELINE SERVICES	Labor & Equipment	$	222,048.00	8	NH
PUBLIC UTILITIES COMMISSION	PUC Assessments	$	158,604.16	4	NH
SENSIT TECHNOLOGIES	Materials & Supplies	$	121,878.37	3	NH
STATE LIFE INSURANCE COMPANY	INSURANCE	$	259,125.00	3	NH & ME
State Of New Hampshire	Taxes	$	359,256.94	5	NH
SWANBIRD & CO.	Financial & Lending	$	1,390,000.00	2	NH & ME
THRIVENT FINANCIAL FOR LUTHERANS	Financial & Lending	$	132,250.00	1	NH & ME
Town Of Hampton,	Taxes	$	147,646.62	3	NH
UNITED OF OMAHA LIFE INSURANCE CO	INSURANCE	$	132,250.00	1	NH & ME
Upsco Inc	Materials & Supplies	$	135,875.49	35	NH

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(17) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations.

Response:

There are no non-utility assets or related costs to report for Northern Utilities, Inc.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(18) Balance sheets and income statements for the previous 3 years.

Response:

Please see attached balance sheets and income statements for Northern Utilities for 2008, 2009 and 2010. The balance sheets are combined for Northern while the income statements are for the New Hampshire division of Northern only.

100

N.H.P.U.C. Report of: Northern Utilities, Inc. For the Year Ended: December 31, 2008

TABLE 10. (Sheet 1 of 2)

BALANCE SHEET ACCOUNTS
Assets and Other Debits

	Balance at beginning of year	Account Number	Title of Account	Detail on Page	Balance at end of year	Increase or (decrease)
	a	b	c	d	e	f
			Fixed Assets:			
1.	314,833,503	100	Fixed Capital - Gas	102	218,432,946	(96,400,557)
2.	0	108	Fixed Capital - Other		0	0
3.	3,461,279	110	Non-Operating Property	104	2,611,051	(850,228)
4.	318,294,782		Total Fixed Assets		221,043,997	(97,250,785)
			Investments:			
5.	0	111	Investments in Affiliated Companies	105	0	0
6.	1,584	112	Miscellaneous Investments	105	1,584	0
7.	0	113	Sinking Funds	106	0	0
8.	0	114	Miscellaneous Special Funds	106	0	0
9.	0	115	Depreciation Funds	106	0	0
10.	1,584		Total Investments		1,584	0
			Current Assets:			
11.	1,373,646	120	Cash		(115,319)	(1,488,965)
12.	1,654,906	121	Special Deposits		7,041,636	5,386,730
13.	2,000	122	Working Funds		2,000	0
14.	0	124	Notes Receivable		0	0
15.	16,847,333	125	Accounts Receivable	107	14,465,253	(2,382,080)
16.	1,066,712	126	Receivables from Affiliated Companies	107	15,486,702	14,419,990
17.	3,518,429	127	Unbilled Revenues		7,885,722	4,367,293
18.	0	128	Interest and Dividends Receivable		0	0
19.	2,780,057	131	Materials and Supplies	107	3,300,739	520,682
20.	959,146	132	Prepayments	106	465,071	(494,075)
21.	0	133	Miscellaneous Current Assets		0	0
22.	28,202,229		Total Current Assets		48,531,804	20,329,575
			Deferred Debits:			
23.	0	140	Unamortized Debt Discount and Expense	108	0	0
24.	0	141	Property Abandoned	104	0	0
25.	0	143	Clearing Accounts		0	0
26.	0	145.1	Maintenance Work in Progress		0	0
27.	0	145.2	Jobbing Accounts		0	0
28.	46,247,010	146	Miscellaneous Suspense	113	57,885,642	11,638,632
29.	46,247,010		Total Deferred Debits		57,885,642	11,638,632
			Company Securities Owned:		0	
30.	0	152	Reacquired Securities	106	0	0
31.	0	154	Unissued Securities		0	0
32.	0		Total Company Securities Owned		0	0
33.	392,745,605		**Total Assets and Other Debits**		327,463,027	(65,282,578)

TABLE 10. (Sheet 2) N.H.P.U.C. Report of: Northern Utilities, Inc. For the Year Ended: December 31, 2008

BALANCE SHEET ACCOUNTS

Liabilities and Other Credits

	Balance at beginning of year	Account Number	Title of Account	Detail on Page	Balance at end of year	Increase or (decrease)
	a	b	c	d	e	f
			Capital Stock:			
1.	1,000	200	Common Stock	109	1,000	0
2.	0	201	Preferred Stock		0	0
3.	0	202	Stock Liability for Conversion		0	0
4.	109,061,810	203	Premium on Capital Stock		65,699,000	(43,362,810)
5.	0	204	Capital Stock Subscribed		0	0
6.	0	205	Installments Paid on Capital Stock		0	0
7.	109,062,810		Total Capital Stock		65,700,000	(43,362,810)
			Non-Corporate Proprietorship:			
8.	0	209	Non-Corporate Proprietorship		0	0
			Long Term Debt:			
9.	62,500,002	210	Bonds and Notes	109	80,000,000	17,499,998
10.	0	211	Capital Lease Obligations		0	0
11.	0	212	Advances from Affiliated Companies		0	0
12.	0	213	Miscellaneous Long Term Debt		0	0
13.	62,500,002		Total Long Term Debt		80,000,000	17,499,998
			Current and Accrued Liabilities:			
14.	0	220	Notes Payable	110	0	0
15.	806,487	222	Accounts Payable		31,486,692	30,680,205
16.	33,204,350	223	Payables to Affiliated Companies	110	42,134,595	8,930,245
17.	0	224	Dividends Declared	108	695,509	695,509
18.	0	225	Matured Bonds		0	0
19.	0	226	Matured Interest		0	0
20.	1,585,641	227	Customers' Deposits (see page 101A)		1,772,478	186,837
21.	80,782	228	Taxes Accrued		(723,664)	(804,446)
22.	302,350	229	Interest Accrued		447,473	145,123
23.	260,754	230.1	Miscellaneous Current Liabilities		199,934	(60,820)
24.	9,553,376	230.2	Miscellaneous Accruals		11,677,821	2,124,445
25.	45,793,740		Total Current and Accrued Liabilities		87,690,838	41,897,098
			Deferred Credits:			
26.	0	240	Unamortized Premiums on Bonds		0	0
27.	9,640,100	242	Miscellaneous Unadjusted Credits	112	12,022,278	2,382,178
28.	9,640,100		Total Deferred Credits		12,022,278	2,382,178
			Reserves:			
29.	68,333,221	250	Depreciation Reserve - ME/NH	111	80,658,072	12,324,851
30.	25,151,457	251	Amortization Reserve	112	(186,460)	(25,337,917)
31.	1,004,460	254	Uncollectible Accounts Reserve	112	1,550,000	545,540
32.	0	255	Casualty and Insurance Reserve	112	0	0
33.	0	258.1	Sinking Funds Reserve	112	0	0
34.	0	258.2	Reserve for Dividends	112	0	0
35.	58,753,106	258.3	Misc. Reserves (see page 101A)	112	(980,616)	(59,733,722)
36.	153,242,244		Total Reserves		81,040,996	(72,201,248)
			Contributions in Aid of Construction:			
37.	0	265	Contributions in Aid of Construction		0	0
			Surplus:			
38.	47,346	270	Capital Surplus	113	0	(47,346)
39.	12,459,363	271	Earned Surplus	113	1,008,915	(11,450,448)
40.	12,506,709		Total Surplus		1,008,915	(11,497,794)
41.	392,745,605		**Total Liabilities and Other Credits**		327,463,027	(65,282,578)

TABLE 40.

INCOME STATEMENT

	Account Number a	Items b	Amount c	Totals d	Increase or (decrease) e
1	1501	Operating Revenues - Gas		67,344,554	(2,319,267)
2	1701-1812	Operation and Maintenance - Gas	57,032,680		(1,941,267)
3	1503	Depreciation - Gas	3,895,047		622,671
4	1504	Amortization - Gas	1,468,580		(295,646)
5	1507	Taxes - Gas	2,631,803		(113,844)
6		Total Revenue Deductions		65,028,110	(1,728,086)
7		Gas Operating Income		2,316,444	(591,181)
8	1508.1	Rent for Lease of Gas Plant	0		0
9	1508.2	Rent from Lease of Gas Plant	0		0
10	1508.3	Joint Facility Rents	232,270		(194,510)
11	1508.4	Rent from Gas Appliances	297,456		102,141
12	1508.5	Miscellaneous Rents	0		0
13	1508.6	Miscellaneous Other Revenues	696,730		299,046
14	1508	Operating Rents - Net		1,226,456	206,677
15		Net Gas Operating Income		3,542,900	(384,504)
16	1509	Operating Income - Other Utility Operations		0	0
17		Net Utility Operating Income		3,542,900	(384,504)
18	1522	Revenues from Non-Operating Property	0		0
19	1523	Dividend Income	0		0
20	1524	Interest Income	0		0
21	1525	Income from Special Funds	0		0
22	1526	Miscellaneous Non-Operating Revenues	85,899		(80,469)
23		Non-Operating Property Revenues		85,899	85,899
24	1527	Non-Operating Revenue Deductions		117,217	117,217
25		Non-Operating Property Income		(31,318)	(31,318)
26		Gross Income		3,511,582	(415,822)
27	1530	Interest on Long-Term Debt	1,407,215		(175,758)
28	1531	Amortization of Debt Discount and Expense	40,151		1,439
29	1533	Taxes Assumed on Interest	0		0
30	1535	Miscellaneous Interest Deductions	32,858		93,108
31	1536	Interest Charges to Property - Credit	(49,360)		(33,032)
32	1537	Miscellaneous Amortization	0		0
33	1538	Miscellaneous Deductions from Income	17,321		3,548
34	1540	Contractual Appropriations of Income	0		0
35		Deductions from Gross Income		1,448,185	(110,695)
36		Income Balance Transferred to Earned Surplus N.H.		2,063,397	(305,127)
37		Income Balance Transferred to Earned Surplus ME.		**(2,007,562)**	(1,806,827)
38		TOTAL		55,835	(2,111,954)

N.H.P.U.C. Report of: Northern Utilities, Inc. For the Year Ended: December 31, 2009

TABLE 10. (Sheet 1 of 2)

BALANCE SHEET ACCOUNTS
Assets and Other Debits

	Balance at beginning of year	Account Number	Title of Account	Detail on Page	Balance at end of year	Increase or (decrease)
	a	b	c	d	e	f
			Fixed Assets:			
1.	218,432,946	100	Fixed Capital - Gas	102	236,987,274	18,554,328
2.	0	108	Fixed Capital - Other		0	0
3.	2,611,051	110	Non-Operating Property	104	2,456,218	(154,833)
4.	221,043,997		Total Fixed Assets		239,443,492	18,399,495
			Investments:			
5.	0	111	Investments in Affiliated Companies	105	0	0
6.	1,584	112	Miscellaneous Investments	105	1,584	0
7.	0	113	Sinking Funds	106	0	0
8.	0	114	Miscellaneous Special Funds	106	0	0
9.	0	115	Depreciation Funds	106	0	0
10.	1,584		Total Investments		1,584	0
			Current Assets:			
11.	(115,319)	120	Cash		(191,465)	(76,146)
12.	7,041,636	121	Special Deposits		2,966,460	(4,075,176)
13.	2,000	122	Working Funds		2,200	200
14.	0	124	Notes Receivable		0	0
15.	14,465,253	125	Accounts Receivable	107	11,189,095	(3,276,158)
16.	15,486,702	126	Receivables from Affiliated Companies	107	2,745,895	(12,740,807)
17.	7,885,722	127	Unbilled Revenues		6,773,152	(1,112,570)
18.	0	128	Interest and Dividends Receivable		0	0
19.	3,300,739	131	Materials and Supplies	107	2,094,267	(1,206,472)
20.	465,071	132	Prepayments	106	1,035,000	569,929
21.	0	133	Miscellaneous Current Assets		0	0
22.	48,531,804		Total Current Assets		26,614,604	(21,917,200)
			Deferred Debits:			
23.	0	140	Unamortized Debt Discount and Expense	108	0	0
24.	0	141	Property Abandoned	104	0	0
25.	0	143	Clearing Accounts		0	0
26.	0	145.1	Maintenance Work in Progress		0	0
27.	0	145.2	Jobbing Accounts		0	0
28.	57,885,642	146	Miscellaneous Suspense	113	48,079,976	(9,805,666)
29.	57,885,642		Total Deferred Debits		48,079,976	(9,805,666)
	0		**Company Securities Owned:**		0	
30.	0	152	Reacquired Securities	106	0	0
31.	0	154	Unissued Securities		0	0
32.	0		Total Company Securities Owned		0	0
33.	327,463,027		**Total Assets and Other Debits**		314,139,656	(13,323,371)

TABLE 10. (Sheet 2) N.H.P.U.C. Report of: Northern Utilities, Inc. For the Year Ended: December 31, 2009

BALANCE SHEET ACCOUNTS

Liabilities and Other Credits

	Balance at beginning of year	Account Number	Title of Account	Detail on Page	Balance at end of year	Increase or (decrease)
	a	b	c	d	e	f
			Capital Stock:			
1.	1,000	200	Common Stock	109	1,000	0
2.	0	201	Preferred Stock		0	0
3.	0	202	Stock Liability for Conversion		0	0
4.	65,699,000	203	Premium on Capital Stock		65,699,000	0
5.	0	204	Capital Stock Subscribed		0	0
6.	0	205	Installments Paid on Capital Stock		0	0
7.	65,700,000		Total Capital Stock		65,700,000	0
			Non-Corporate Proprietorship:			
8.	0	209	Non-Corporate Proprietorship		0	0
			Long Term Debt:			
9.	80,000,000	210	Bonds and Notes	109	80,000,000	0
10.	0	211	Capital Lease Obligations		0	0
11.	0	212	Advances from Affiliated Companies		0	0
12.	0	213	Miscellaneous Long Term Debt		0	0
13.	80,000,000		Total Long Term Debt		80,000,000	0
			Current and Accrued Liabilities:			
14.	0	220	Notes Payable	110	0	0
15.	31,486,692	222	Accounts Payable		10,643,267	(20,843,425)
16.	42,134,595	223	Payables to Affiliated Companies	110	46,899,316	4,764,721
17.	695,509	224	Dividends Declared	108	1,766,000	1,070,491
18.	0	225	Matured Bonds		0	0
19.	0	226	Matured Interest		0	0
20.	1,772,478	227	Customers' Deposits (see page 101A)		1,811,181	38,703
21.	(723,664)	228	Taxes Accrued		1,161,430	1,885,094
22.	447,473	229	Interest Accrued		463,454	15,981
23.	199,934	230.1	Miscellaneous Current Liabilities		8,413	(191,521)
24.	11,677,821	230.2	Miscellaneous Accruals		8,413,356	(3,264,465)
25.	87,690,838		Total Current and Accrued Liabilities		71,166,417	(16,524,421)
			Deferred Credits:			
26.	0	240	Unamortized Premiums on Bonds		0	0
27.	12,022,278	242	Miscellaneous Unadjusted Credits	112	12,323,233	300,955
28.	12,022,278		Total Deferred Credits		12,323,233	300,955
			Reserves:			
29.	80,658,072	250	Depreciation Reserve - ME/NH	111	84,220,428	3,562,356
30.	(186,460)	251	Amortization Reserve	112	(2,486,066)	(2,299,606)
31.	1,550,000	254	Uncollectible Accounts Reserve	112	451,012	(1,098,988)
32.	0	255	Casualty and Insurance Reserve	112	0	0
33.	0	258.1	Sinking Funds Reserve	112	0	0
34.	0	258.2	Reserve for Dividends	112	0	0
35.	(980,616)	258.3	Misc. Reserves	112	1,020,776	2,001,392
36.	81,040,996		Total Reserves		83,206,150	2,165,154
			Contributions in Aid of Construction:			
37.	0	265	Contributions in Aid of Construction		0	0
			Surplus:			
38.	0	270	Capital Surplus	113	0	0
39.	1,008,915	271	Earned Surplus	113	1,743,856	734,941
40.	1,008,915		Total Surplus		1,743,856	734,941
41.	327,463,027		**Total Liabilities and Other Credits**		314,139,656	(13,323,371)

TABLE 40.

INCOME STATEMENT

	Account Number a	Items b	Amount c	Totals d	Increase or (decrease) e
1	1501	Operating Revenues - Gas		56,314,782	(11,029,772)
2	1701-1812	Operation and Maintenance - Gas	44,432,058		(12,600,622)
3	1503	Depreciation - Gas	4,093,160		198,113
4	1504	Amortization - Gas	(1,019,043)		(2,487,623)
5	1507	Taxes - Gas	3,364,503		732,700
6		Total Revenue Deductions		50,870,678	(14,157,432)
7		Gas Operating Income		5,444,104	3,127,660
8	1508.1	Rent for Lease of Gas Plant	0		0
9	1508.2	Rent from Lease of Gas Plant	0		0
10	1508.3	Joint Facility Rents	0		(232,270)
11	1508.4	Rent from Gas Appliances	591,860		294,404
12	1508.5	Miscellaneous Rents	0		0
13	1508.6	Miscellaneous Other Revenues	130,437		(566,293)
14	1508	Operating Rents - Net		722,297	(504,159)
15		Net Gas Operating Income		6,166,401	2,623,501
16	1509	Operating Income - Other Utility Operations		0	0
17		Net Utility Operating Income		6,166,401	2,623,501
18	1522	Revenues from Non-Operating Property	0		0
19	1523	Dividend Income	0		0
20	1524	Interest Income	0		0
21	1525	Income from Special Funds	0		0
22	1526	Miscellaneous Non-Operating Revenues	120,873		34,974
23		Non-Operating Property Revenues		120,873	34,974
24	1527	Non-Operating Revenue Deductions		(955)	(118,172)
25		Non-Operating Property Income		121,828	153,146
26		Gross Income		6,288,229	2,776,647
27	1530	Interest on Long-Term Debt	3,244,950		1,837,735
28	1531	Amortization of Debt Discount and Expense	59,093		18,942
29	1533	Taxes Assumed on Interest	0		0
30	1535	Miscellaneous Interest Deductions	34,798		1,940
31	1536	Interest Charges to Property - Credit	(24,150)		25,210
32	1537	Miscellaneous Amortization	0		0
33	1538	Miscellaneous Deductions from Income	63,169		45,848
34	1540	Contractual Appropriations of Income	0		0
35		Deductions from Gross Income		3,377,860	1,929,675
36		Income Balance Transferred to Earned Surplus N.H.		2,910,369	846,972
37		Income Balance Transferred to Earned Surplus ME.		2,868,572	4,876,134
38		TOTAL		5,778,941	5,723,106

N.H.P.U.C. Report of: Northern Utilities, Inc. For the Year Ended: December 31, 2010

TABLE 10. (Sheet 1 of 2)

BALANCE SHEET ACCOUNTS

Assets and Other Debits

	Balance at beginning of year	Account Number	Title of Account	Detail on Page	Balance at end of year	Increase or (decrease)
	a	b	c	d	e	f
			Fixed Assets:			
1.	236,987,274	100	Fixed Capital - Gas	102	255,703,797	18,716,523
2.	0	108	Fixed Capital - Other			0
3.	2,456,218	110	Non-Operating Property	104	2,468,520	12,302
4.	239,443,492		Total Fixed Assets		258,172,317	18,728,825
			Investments:			
5.	0	111	Investments in Affiliated Companies	105	0	0
6.	1,584	112	Miscellaneous Investments	105	1,584	0
7.	0	113	Sinking Funds	106	0	0
8.	0	114	Miscellaneous Special Funds	106	0	0
9.	0	115	Depreciation Funds	106	0	0
10.	1,584		Total Investments		1,584	0
			Current Assets:			
11.	(191,465)	120	Cash		(195,183)	(3,718)
12.	2,966,460	121	Special Deposits		1,543,183	(1,423,277)
13.	2,200	122	Working Funds		2,000	(200)
14.	0	124	Notes Receivable			0
15.	11,189,095	125	Accounts Receivable	107	14,772,248	3,583,153
16.	2,745,895	126	Receivables from Affiliated Companies	107	701,862	(2,044,033)
17.	6,773,152	127	Unbilled Revenues		6,591,021	(182,131)
18.	0	128	Interest and Dividends Receivable			0
19.	2,094,267	131	Materials and Supplies	107	2,105,844	11,577
20.	1,035,000	132	Prepayments	106	1,304,060	269,060
21.	0	133	Miscellaneous Current Assets		0	0
22.	26,614,604		Total Current Assets		26,825,035	210,431
			Deferred Debits:			
23.	0	140	Unamortized Debt Discount and Expense	108	0	0
24.	0	141	Property Abandoned	104	0	0
25.	0	143	Clearing Accounts		0	0
26.	0	145.1	Maintenance Work in Progress		0	0
27.	0	145.2	Jobbing Accounts		0	0
28.	48,079,976	146	Miscellaneous Suspense	113	49,978,243	1,898,267
29.	48,079,976		Total Deferred Debits		49,978,243	1,898,267
	0		**Company Securities Owned:**		0	
30.	0	152	Reacquired Securities	106	0	0
31.	0	154	Unissued Securities		0	0
32.	0		Total Company Securities Owned		0	0
33.	314,139,656		**Total Assets and Other Debits**		334,977,179	20,837,523

TABLE 10. (Sheet 2) N.H.P.U.C. Report of: Northern Utilities, Inc. For the Year Ended: December 31, 2010

BALANCE SHEET ACCOUNTS

Liabilities and Other Credits

	Balance at beginning of year	Account Number	Title of Account	Detail on Page	Balance at end of year	Increase or (decrease)
	a	b	c	d	e	f
			Capital Stock:			
1.	1,000	200	Common Stock	109	1,000	0
2.	0	201	Preferred Stock		0	0
3.	0	202	Stock Liability for Conversion		0	0
4.	65,699,000	203	Premium on Capital Stock		73,199,000	7,500,000
5.	0	204	Capital Stock Subscribed		0	0
6.	0	205	Installments Paid on Capital Stock		0	0
7.	65,700,000		Total Capital Stock		73,200,000	7,500,000
			Non-Corporate Proprietorship:			
8.	0	209	Non-Corporate Proprietorship		0	0
			Long Term Debt:			
9.	80,000,000	210	Bonds and Notes	109	105,000,000	25,000,000
10.	0	211	Capital Lease Obligations		0	0
11.	0	212	Advances from Affiliated Companies		0	0
12.	0	213	Miscellaneous Long Term Debt		0	0
13.	80,000,000		Total Long Term Debt		105,000,000	25,000,000
			Current and Accrued Liabilities:			
14.	0	220	Notes Payable	110		0
15.	10,643,267	222	Accounts Payable		12,266,132	1,622,865
16.	46,899,316	223	Payables to Affiliated Companies	110	32,508,156	(14,391,160)
17.	1,766,000	224	Dividends Declared	108	620,000	(1,146,000)
18.	0	225	Matured Bonds			0
19.	0	226	Matured Interest			0
20.	1,811,181	227	Customers' Deposits (see page 101A)		1,357,979	(453,202)
21.	1,161,430	228	Taxes Accrued		11,544	(1,149,886)
22.	463,454	229	Interest Accrued		943,949	480,495
23.	8,413	230.1	Miscellaneous Current Liabilities		1,123,417	1,115,004
24.	8,413,356	230.2	Miscellaneous Accruals		8,623,981	210,625
25.	71,166,417		Total Current and Accrued Liabilities		57,455,158	(13,711,259)
			Deferred Credits:			
26.	0	240	Unamortized Premiums on Bonds		0	0
27.	12,323,233	242	Miscellaneous Unadjusted Credits	112	13,860,893	1,537,660
28.	12,323,233		Total Deferred Credits		13,860,893	1,537,660
			Reserves:			
29.	84,220,428	250	Depreciation Reserve - ME/NH	111	91,579,242	7,358,814
30.	(2,486,066)	251	Amortization Reserve	112	(4,379,815)	(1,893,749)
31.	451,012	254	Uncollectible Accounts Reserve	112	438,102	(12,910)
32.	0	255	Casualty and Insurance Reserve	112		0
33.	0	258.1	Sinking Funds Reserve	112		0
34.	0	258.2	Reserve for Dividends	112		0
35.	1,020,776	258.3	Misc. Reserves	112	(1,504,167)	(2,524,943)
36.	83,206,150		Total Reserves		86,133,362	2,927,212
			Contributions in Aid of Construction:			
37.	0	265	Contributions in Aid of Construction		0	0
			Surplus:			
38.	0	270	Capital Surplus	113	0	0
39.	1,743,856	271	Earned Surplus	113	(672,234)	(2,416,090)
40.	1,743,856		Total Surplus		(672,234)	(2,416,090)
41.	314,139,656		**Total Liabilities and Other Credits**		334,977,179	20,837,523

TABLE 40.

INCOME STATEMENT

	Account Number	Items	Amount	Totals	Increase or (decrease)
	a	b	c	d	e
1	1501	Operating Revenues - Gas		60,060,896	3,746,114
2	1701-1812	Operation and Maintenance - Gas	49,593,034		5,160,976
3	1503	Depreciation - Gas	4,347,100		253,940
4	1504	Amortization - Gas	(768,535)		250,508
5	1507	Taxes - Gas	2,358,059		(1,006,444)
6		Total Revenue Deductions		55,529,658	4,658,980
7		Gas Operating Income		4,531,238	(912,866)
8	1508.1	Rent for Lease of Gas Plant	0		0
9	1508.2	Rent from Lease of Gas Plant	0		0
10	1508.3	Joint Facility Rents	0		0
11	1508.4	Rent from Gas Appliances	(225,249)		(817,109)
12	1508.5	Miscellaneous Rents	0		0
13	1508.6	Miscellaneous Other Revenues	(4,413)		(134,850)
14	1508	Operating Rents - Net		(229,662)	(951,959)
15		Net Gas Operating Income		4,301,576	(1,864,825)
16	1509	Operating Income - Other Utility Operations		0	0
17		Net Utility Operating Income		4,301,576	(1,864,825)
18	1522	Revenues from Non-Operating Property	0		0
19	1523	Dividend Income	0		0
20	1524	Interest Income	0		0
21	1525	Income from Special Funds	0		0
22	1526	Miscellaneous Non-Operating Revenues	168,459		47,586
23		Non-Operating Property Revenues		168,459	47,586
24	1527	Non-Operating Revenue Deductions		(17,021)	(16,066)
25		Non-Operating Property Income		185,480	63,652
26		Gross Income		4,487,056	(1,801,173)
27	1530	Interest on Long-Term Debt	3,478,950		234,000
28	1531	Amortization of Debt Discount and Expense	72,751		13,658
29	1533	Taxes Assumed on Interest			0
30	1535	Miscellaneous Interest Deductions	24,026		(10,772)
31	1536	Interest Charges to Property - Credit	(42,604)		(18,454)
32	1537	Miscellaneous Amortization			0
33	1538	Miscellaneous Deductions from Income	97,467		34,298
34	1540	Contractual Appropriations of Income	0		0
35		Deductions from Gross Income		3,630,590	252,730
36		Income Balance Transferred to Earned Surplus N.H.		856,466	(2,053,903)
37		Income Balance Transferred to Earned Surplus ME.		(792,556)	(3,661,128)
38		TOTAL		63,910	(5,715,031)

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(19) Quarterly income statements for the previous 5 years.

Response:

On December 1, 2008, Northern Utilities, Inc. (“Northern Utilities”) was acquired by Unitil Corporation from Bay State Gas Company (“Bay State”), a wholly-owned subsidiary of NiSource, Inc. (“NiSource”.) Prior to December 1, 1, 2008, when Northern Utilities was under the ownership of Bay State / NiSource, no quarterly income statements were prepared.

Accordingly, please find attached for Northern Utilities, quarterly income statements for quarters one through three of 2009 and 2010, as well as the one month period ending December 31, 2008.

For the quarterly periods ending December 31, 2009 and 2010, quarterly statements are not available. Therefore, annual amounts for 2009 and 2010 are being provided. Quarterly amounts for the periods ended December 31, 2009 and 2010 can be derived by subtracting the September YTD amounts from the YTD amounts in the December income statements.

NORTHERN UTILITIES, INC.
STATEMENT OF EARNINGS
($ in Millions)

	Period Ended December 31, 2008
Operating Revenues	$ 21.8
Operating Expenses:	
Purchased Gas	16.8
Operation and Maintenance	1.2
Depreciation and Amortization	0.5
Provisions for Taxes:	
Local Property and Other	0.2
Federal and State Income	1.1
Total Operating Expenses	19.8
Operating Income	2.0
Non-Operating Income	0.1
Income Before Interest Expense	2.1
Interest Expense	0.4
Net Income	$ 1.7

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENT OF EARNINGS
(Millions, Except Common Shares and Per Share Data)
(UNAUDITED)

Three Months Ended March 31,	2009
Operating Revenues	$ 54.9
Operating Expenses:	
Purchased Gas	37.6
Operation and Maintenance	3.2
Conservation & Load Management	0.5
Depreciation and Amortization	1.7
Provisions for Taxes:	
Local Property and Other	0.7
Federal and State Income	3.7
Total Operating Expense	47.4
Operating Income	7.5
Non-operating Income	0.1
Income Before Interest Expense	7.6
Interest Expense	1.7
Net Income	$ 5.9

The accompanying notes are an integral part of these financial statements.

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
(Millions, Except Common Shares and Per Share Data)
(UNAUDITED)

	(UNAUDITED) Three Months Ended June 30, 2009	(UNAUDITED) Six Months Ended June 30, 2009
Operating Revenues	$ 17.4	$ 72.3
Operating Expenses:		
Purchased Gas	9.4	47.0
Operation and Maintenance	3.5	6.7
Conservation & Load Management	0.5	1.0
Depreciation and Amortization	1.8	3.5
Provisions for Taxes:		
Local Property and Other	0.7	1.4
Federal and State Income	(0.1)	3.6
Total Operating Expense	15.8	63.2
Operating Income	1.6	9.1
Non-operating Income	0.1	0.2
Income Before Interest Expense	1.7	9.3
Interest Expense	1.7	3.4
Net Income	$ -	$ 5.9

(The accompanying notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
(Millions, Except Common Shares and Per Share Data)
(UNAUDITED)

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Operating Revenues	$ 10.8	$ 83.1
Operating Expenses:		
Purchased Gas	5.4	52.4
Operation and Maintenance	4.7	11.4
Conservation & Load Management	0.3	1.3
Depreciation and Amortization	1.7	5.2
Provisions for Taxes:		
Local Property and Other	0.7	2.1
Federal and State Income	(1.7)	1.9
Total Operating Expense	11.1	74.3
Operating Income	(0.3)	8.8
Non-operating Income	0.1	0.3
Income Before Interest Expense	(0.2)	9.1
Interest Expense	1.7	5.1
Net Income	$ (1.9)	$ 4.0

(The accompanying notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
($ in Millions)

	Year Ended December 31, 2009	Period December 1 to December 31, 2008
Operating Revenues	$ 116.0	$ 21.8
Operating Expenses:		
Purchased Gas	73.2	16.8
Operation and Maintenance	14.8	1.2
Conservation & Load Management	1.5	---
Depreciation and Amortization	7.8	0.5
Provisions for Taxes:		
Local Property and Other	2.9	0.2
Federal and State Income	3.4	1.1
Total Operating Expenses	103.6	19.8
Operating Income	12.4	2.0
Non-Operating Income	0.3	0.1
Income Before Interest Expense	12.7	2.1
Interest Expense	6.9	0.4
Net Income Applicable to Common Stock	$ 5.8	$ 1.7

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
(Millions, Except Common Shares and Per Share Data)
(UNAUDITED)

	Three Months Ended March 31, 2010		Three Months Ended March 31, 2009	
Operating Revenues	$	48.4	$	54.9
Operating Expenses:				
Purchased Gas		32.0		37.6
Operation and Maintenance		5.7		3.2
Conservation & Load Management		0.5		0.5
Depreciation and Amortization		2.2		1.7
Provisions for Taxes:				
Local Property and Other		0.8		0.7
Federal and State Income		2.2		3.7
Total Operating Expense		43.4		47.4
Operating Income		5.0		7.5
Non-operating Income		-		0.1
Income Before Interest Expense		5.0		7.6
Interest Expense		1.8		1.7
Net Income	$	3.2	$	5.9

(The accompanying notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
(Millions, Except Common Shares and Per Share Data)

	(UNAUDITED) Three Months Ended June 30,		(UNAUDITED) Six Months Ended June 30,	
	2010	2009	**2010**	2009
Operating Revenues:	**$ 18.0**	$ 17.4	**$ 66.4**	$ 72.3
Operating Expenses:				
Purchased Gas	**12.1**	9.4	**44.1**	47.0
Operation and Maintenance	**4.1**	3.5	**9.8**	6.7
Conservation & Load Management	**0.7**	0.5	**1.2**	1.0
Depreciation and Amortization	**2.3**	1.8	**4.5**	3.5
Provisions for Taxes:				
Local Property and Other	**0.7**	0.7	**1.5**	1.4
Federal and State Income	**(1.2)**	(0.1)	**1.0**	3.6
Total Operating Expense	**18.7**	15.8	**62.1**	63.2
Operating Income (Loss)	**(0.7)**	1.6	**4.3**	9.1
Non-operating Income	**0.1**	0.1	**0.1**	0.2
Income (Loss) Before Interest Expense	**(0.6)**	1.7	**4.4**	9.3
Interest Expense	**1.9**	1.7	**3.7**	3.4
Net Income (Loss)	**$ (2.5)**	$ -	**$ 0.7**	$ 5.9

(The accompanying notes are an integral part of these consolidated financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
(Millions)

	(UNAUDITED) Three Months Ended September 30,		(UNAUDITED) Nine Months Ended September 30,	
	2010	2009	**2010**	2009
Operating Revenues:	**$ 13.2**	$ 10.8	**$ 79.6**	$ 83.1
Operating Expenses:				
Purchased Gas	**7.5**	5.4	**51.6**	52.4
Operation and Maintenance	**5.0**	4.7	**14.8**	11.4
Conservation & Load Management	**0.5**	0.3	**1.7**	1.3
Depreciation and Amortization	**2.0**	1.7	**6.5**	5.2
Provisions (Benefit) for Taxes:				
Local Property and Other	**0.8**	0.7	**2.3**	2.1
Federal and State Income	**(2.2)**	(1.7)	**(1.2)**	1.9
Total Operating Expense	**13.6**	11.1	**75.7**	74.3
Operating Income (Loss)	**(0.4)**	(0.3)	**3.9**	8.8
Non-operating Income	**-**	0.1	**0.1**	0.3
Income (Loss) Before Interest Expense	**(0.4)**	(0.2)	**4.0**	9.1
Interest Expense	**1.9**	1.7	**5.6**	5.1
Net Income (Loss)	**$ (2.3)**	$ (1.9)	**$ (1.6)**	$ 4.0

(The accompanying notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
($ in Millions)

	Year Ended December 31, 2010	Year Ended December 31, 2009	Period December 1 to December 31, 2008
Operating Revenues	$ 118.3	$ 116.0	$ 21.8
Operating Expenses:			
Purchased Gas	77.5	73.2	16.8
Operation and Maintenance	19.1	14.8	1.2
Conservation & Load Management	2.0	1.5	---
Depreciation and Amortization	8.9	7.8	0.5
Provisions for Taxes:			
Local Property and Other	3.3	2.9	0.2
Federal and State Income	0.1	3.4	1.1
Total Operating Expenses	110.9	103.6	19.8
Operating Income	7.4	12.4	2.0
Non-Operating Income	0.3	0.3	0.1
Income Before Interest Expense	7.7	12.7	2.1
Interest Expense	7.6	6.9	0.4
Net Income Applicable to Common Stock	$ 0.1	$ 5.8	$ 1.7

(The accompanying Notes are an integral part of these financial statements.)

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(20) Quarterly sales volumes for the previous 5 years, itemized for residential and other classifications of service.

Response:

On December 1, 2008, Northern Utilities, Inc. was acquired by Unitil Corporation from Bay State Gas Company a wholly-owned subsidiary of NiSource, Inc.

Accordingly for the periods May 2006 through December 2008 please refer to “PUC 1604 01a 20 Attachment 2.pdf”, which is a copy of the Summer and Winter Form III from the Cost of Gas Reconciliation filing.

For the periods 2009 and 2010 please refer to “PUC 1604 01a 20 Attachment 1.pdf”

Northern Utilities, Inc.
PUC 1604 01a 20
Attachment 1
Page 1 of 1

Quarterly Sales Volumes (ccf)

	Q1 Mar-10	Q2 Jun-10	Q3 Sep-10	Q4 Dec-10	TOTAL 2010
R5	7,530,433	2,738,295	939,086	3,239,939	14,447,753
R6	128,727	76,690	53,421	79,750	338,589
R10	296,504	108,815	49,075	155,865	610,259
R11	2,077	1,038	1,239	7,745	12,099
G40	4,634,051	1,317,397	346,684	1,787,772	8,085,904
G41	5,340,694	1,803,127	673,396	2,447,580	10,264,795
G42	2,161,070	638,400	613,556	1,858,184	5,271,210
G50	732,462	490,932	428,535	513,753	2,165,682
G51	1,255,446	835,127	774,582	933,263	3,798,418
G52	3,571,025	2,380,164	2,096,323	3,100,232	11,147,743
Special Contract	2,876,492	2,574,618	2,522,758	2,479,812	10,453,680
Interruptible	-	-	-	-	-
	28,528,979	12,964,604	8,498,654	16,603,896	66,596,133
Accrued Consumption					
Commercial	-	-	-	-	-
Industrial	-	-	-	-	-
	-	-	-	-	-
Grand Total	28,528,979	12,964,604	8,498,654	16,603,896	66,596,133

	Q1 Mar-09	Q2 Jun-09	Q3 Sep-09	Q4 Dec-09	TOTAL 2009
R5	8,002,316	2,839,378	1,138,260	3,008,550	14,988,504
R6	119,931	78,762	50,080	75,029	323,802
R10	438,778	215,898	43,970	128,233	826,879
R11	1,290	1,128	724	1,447	4,589
G40	5,274,570	1,593,944	298,274	1,594,882	8,761,670
G41	5,700,780	2,112,908	714,874	2,675,544	11,204,106
G42	1,870,295	1,573,902	657,391	1,904,827	6,006,415
G50	745,588	517,772	429,420	503,605	2,196,385
G51	1,380,947	967,564	721,705	986,500	4,056,716
G52	3,223,540	3,054,038	1,857,555	2,902,452	11,037,585
Special Contract	2,832,241	3,846,225	2,686,311	2,628,245	11,993,022
Interruptible	-	-	-	-	-
	29,590,276	16,801,519	8,598,564	16,409,313	71,399,672
Accrued Consumption					
Commercial	88,335	(1,119,285)	-	-	(1,030,950)
Industrial	(116,818)	(1,550,885)	-	-	(1,667,703)
	(28,483)	(2,670,170)	-	-	(2,698,653)
Grand Total	29,561,793	14,131,349	8,598,564	16,409,313	68,701,019

29-Jan-07
FORM III
Schedule 3
Page 2 of 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2006 - October 2006

GAS COST RECOVERY FOR THE MONTH OF : May-06 Prorated

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)	219,272	6,382	114,625	192,707	80,807	42,499	169,319	91,492	355,300	1,272,403
Demand/Commodity Rate	$ 1.0457	$ 1.0457	$ 1.0472	$ 1.0472	$ 1.0472	$ 1.0441	$ 1.0441	$ 1.0441	$ 1.0441	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 1.0104	$ 1.0104	$ 1.0119	$ 1.0119	$ 1.0119	$ 1.0088	$ 1.0088	$ 1.0088	$ 1.0088	
Demand/Commodity Collections	$ 229,293	$ 6,673	$ 120,035	$ 201,803	$ 84,621	$ 44,373	$ 176,786	$ 95,526	$ 370,969	$ 1,330,080
Prior Period Reconciliation	$ (9,231)	$ (269)	$ (4,826)	$ (8,113)	$ (3,402)	$ (1,789)	$ (7,128)	$ (3,852)	$ (14,958)	$ (53,568)
Working Capital Allowance	$ 460	$ 13	$ 241	$ 405	$ 170	$ 89	$ 356	$ 192	$ 746	$ 2,672
Bad Debt Allowance	$ 1,031	$ 30	$ 539	$ 906	$ 380	$ 200	$ 796	$ 430	$ 1,670	$ 5,980
Total Summer COG Revenues	$ 221,553	$ 6,448	$ 115,989	$ 195,001	$ 81,769	$ 42,872	$ 170,809	$ 92,297	$ 358,427	$ 1,285,164
Check	221,553	6,448	115,989	195,001	81,769	42,872	170,809	92,297	358,427	1,285,164

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2006 - October 2006

GAS COST RECOVERY FOR THE MONTH OF : 6/1/2006 (old)

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)	506,556	17,075	163,903	124,617	10,001	96,688	139,801	6,900	0	1,065,539
Demand/Commodity Rate	$ 1.0457	$ 1.0457	$ 1.0472	$ 1.0472	$ 1.0472	$ 1.0441	$ 1.0441	$ 1.0441	$ 1.0441	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 1.0104	$ 1.0104	$ 1.0119	$ 1.0119	$ 1.0119	$ 1.0088	$ 1.0088	$ 1.0088	$ 1.0088	
Demand/Commodity Collections	$ 529,705	$ 17,855	$ 171,639	$ 130,499	$ 10,473	$ 100,952	$ 145,966	$ 7,204	$ -	$ 1,114,292
Prior Period Reconciliation	$ (21,326)	$ (719)	$ (6,900)	$ (5,246)	$ (421)	$ (4,071)	$ (5,886)	$ (290)	$ -	$ (44,859)
Working Capital Allowance	$ 1,064	$ 36	$ 344	$ 262	$ 21	$ 203	$ 294	$ 14	$ -	$ 2,238
Bad Debt Allowance	$ 2,381	$ 80	$ 770	$ 586	$ 47	$ 454	$ 657	$ 32	$ -	$ 5,008
Total Summer COG Revenues	$ 511,824	$ 17,253	$ 165,853	$ 126,100	$ 10,120	$ 97,539	$ 141,031	$ 6,961	$ -	$ 1,076,679
Check	511,824	17,253	165,853	126,100	10,120	97,539	141,031	6,961	-	1,076,679

GAS COST RECOVERY FOR THE MONTH OF : 6/1/2006 (new)

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)	161,275	7,334	52,663	104,052	26,676	44,497	132,727	242,213	159,341	930,779
Demand/Commodity Rate	$ 0.9162	$ 0.9162	$ 0.9178	$ 0.9178	$ 0.9178	$ 0.9146	$ 0.9146	$ 0.9146	$ 0.9146	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 0.8809	$ 0.8809	$ 0.8825	$ 0.8825	$ 0.8825	$ 0.8793	$ 0.8793	$ 0.8793	$ 0.8793	
Demand/Commodity Collections	$ 147,760	$ 6,719	$ 48,334	$ 95,499	$ 24,484	$ 40,697	$ 121,392	$ 221,528	$ 145,733	$ 852,147
Prior Period Reconciliation	$ (6,790)	$ (309)	$ (2,217)	$ (4,381)	$ (1,123)	$ (1,873)	$ (5,588)	$ (10,197)	$ (6,708)	$ (39,186)
Working Capital Allowance	$ 339	$ 15	$ 111	$ 219	$ 56	$ 93	$ 279	$ 509	$ 335	$ 1,955
Bad Debt Allowance	$ 758	$ 34	$ 248	$ 489	$ 125	$ 209	$ 624	$ 1,138	$ 749	$ 4,375
Total Summer COG Revenues	$ 142,067	$ 6,461	$ 46,475	$ 91,826	$ 23,542	$ 39,126	$ 116,706	$ 212,978	$ 140,109	$ 819,291
Check	142,067	6,461	46,475	91,826	23,542	39,126	116,706	212,978	140,109	819,291

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2006 - October 2006

GAS COST RECOVERY FOR THE MONTH OF : Jul-06

0

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)	369,461	21,335	103,523	107,982	277,680	143,613	251,485	71,938	(159,341)	1,187,676
Demand/Commodity Rate	$ 0.9162	$ 0.9162	$ 0.9178	$ 0.9178	$ 0.9178	$ 0.9146	$ 0.9146	$ 0.9146	$ 0.9146	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 0.8809	$ 0.8809	$ 0.8825	$ 0.8825	$ 0.8825	$ 0.8793	$ 0.8793	$ 0.8793	$ 0.8793	
Demand/Commodity Collections	$ 338,500	$ 19,547	$ 95,013	$ 99,106	$ 254,855	$ 131,348	$ 230,008	$ 65,794	$ (145,733)	$ 1,088,439
Prior Period Reconciliation	$ (15,554)	$ (898)	$ (4,358)	$ (4,546)	$ (11,690)	$ (6,046)	$ (10,588)	$ (3,029)	$ 6,708	$ (50,001)
Working Capital Allowance	$ 776	$ 45	$ 217	$ 227	$ 583	$ 302	$ 528	$ 151	$ (335)	$ 2,494
Bad Debt Allowance	$ 1,736	$ 100	$ 487	$ 508	$ 1,305	$ 675	$ 1,182	$ 338	$ (749)	$ 5,582
Total Summer COG Revenues	$ 325,458	$ 18,794	$ 91,359	$ 95,294	$ 245,053	$ 126,279	$ 221,131	$ 63,255	$ (140,109)	$ 1,046,514
Check	325,458	18,794	91,359	95,294	245,053	126,279	221,131	63,255	(140,109)	1,046,514

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2006 - October 2006

GAS COST RECOVERY FOR THE MONTH OF : Aug-06

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)-old rate	306,507	16,440	84,251	135,277	75,781	136,604	230,832	87,155	0	1,072,847
Demand/Commodity Rate	$ 0.9162	$ 0.9162	$ 0.9178	$ 0.9178	$ 0.9178	$ 0.9146	$ 0.9146	$ 0.9146	$ 0.9146	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 0.8809	$ 0.8809	$ 0.8825	$ 0.8825	$ 0.8825	$ 0.8793	$ 0.8793	$ 0.8793	$ 0.8793	
Demand/Commodity Collections	$ 280,822	$ 15,062	$ 77,326	$ 124,157	$ 69,552	$ 124,938	$ 211,119	$ 79,712	$ -	$ 982,688
Prior Period Reconciliation	$ (12,904)	$ (692)	$ (3,547)	$ (5,695)	$ (3,190)	$ (5,751)	$ (9,718)	$ (3,669)	$ -	$ (45,167)
Working Capital Allowance	$ 644	$ 35	$ 177	$ 284	$ 159	$ 287	$ 485	$ 183	$ -	$ 2,253
Bad Debt Allowance	$ 1,441	$ 77	$ 396	$ 636	$ 356	$ 642	$ 1,085	$ 410	$ -	$ 5,042
Total Summer COG Revenues	$ 270,002	$ 14,482	$ 74,352	$ 119,382	$ 66,877	$ 120,116	$ 202,971	$ 76,635	$ -	$ 944,816
Check	270,002	14,482	74,352	119,382	66,877	120,116	202,971	76,635	-	944,816

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2006 - October 2006

FORM III
Schedule 3
Page 6 of 8

GAS COST RECOVERY FOR THE MONTH OF : 9/1/2006 (old)

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)-old rate	239,886	14,520	61,974	57,379	9,979	107,126	130,996	15,169	0	637,028
Demand/Commodity Rate	$ 0.9162	$ 0.9162	$ 0.9178	$ 0.9178	$ 0.9178	$ 0.9146	$ 0.9146	$ 0.9146	$ 0.9146	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 0.8809	$ 0.8809	$ 0.8825	$ 0.8825	$ 0.8825	$ 0.8793	$ 0.8793	$ 0.8793	$ 0.8793	
Demand/Commodity Collections	$ 219,784	$ 13,303	$ 56,879	$ 52,662	$ 9,159	$ 97,977	$ 119,809	$ 13,873	$ -	$ 583,446
Prior Period Reconciliation	$ (10,099)	$ (611)	$ (2,609)	$ (2,416)	$ (420)	$ (4,510)	$ (5,515)	$ (639)	$ -	$ (26,819)
Working Capital Allowance	$ 504	$ 30	$ 130	$ 120	$ 21	$ 225	$ 275	$ 32	$ -	$ 1,338
Bad Debt Allowance	$ 1,127	$ 68	$ 291	$ 270	$ 47	$ 503	$ 616	$ 71	$ -	$ 2,994
Total Summer COG Revenues	$ 211,316	$ 12,790	$ 54,692	$ 50,637	$ 8,806	$ 94,196	$ 115,185	$ 13,338	$ -	$ 560,959
Check	211,316	12,790	54,692	50,637	8,806	94,196	115,185	13,338	-	560,959

GAS COST RECOVERY FOR THE MONTH OF : 9/1/2006 (new)

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)-new rate	119,790	6,517	47,968	79,757	45,252	49,473	144,662	73,306	0	566,726
Demand/Commodity Rate	$ 0.9891	$ 0.9891	$ 0.9907	$ 0.9907	$ 0.9907	$ 0.9875	$ 0.9875	$ 0.9875	$ 0.9875	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 0.9538	$ 0.9538	$ 0.9554	$ 0.9554	$ 0.9554	$ 0.9522	$ 0.9522	$ 0.9522	$ 0.9522	
Demand/Commodity Collections	$ 118,484	$ 6,446	$ 47,522	$ 79,015	$ 44,831	$ 48,855	$ 142,854	$ 72,390	$ -	$ 560,398
Prior Period Reconciliation	$ (5,043)	$ (274)	$ (2,019)	$ (3,358)	$ (1,905)	$ (2,083)	$ (6,090)	$ (3,086)	$ -	$ (23,859)
Working Capital Allowance	$ 252	$ 14	$ 101	$ 167	$ 95	$ 104	$ 304	$ 154	$ -	$ 1,190
Bad Debt Allowance	$ 563	$ 31	$ 225	$ 375	$ 213	$ 233	$ 680	$ 345	$ -	$ 2,664
Total Summer COG Revenues	$ 114,256	$ 6,216	$ 45,829	$ 76,200	$ 43,234	$ 47,108	$ 137,747	$ 69,802	$ -	$ 540,392
Check	114,256	6,216	45,829	76,200	43,234	47,108	137,747	69,802	-	540,392
										1,101,352

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2006 - October 2006

GAS COST RECOVERY FOR THE MONTH OF : Oct-06

		Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)-new rate		474,891	19,147	163,832	272,565	64,001	126,591	235,378	82,317	0	1,438,722
Demand/Commodity Rate	$	0.9891	$ 0.9891	$ 0.9907	$ 0.9907	$ 0.9907	$ 0.9875	$ 0.9875	$ 0.9875	$ 0.9875	
Prior Period Reconciliation	$	(0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$	0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$	0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$	0.9538	$ 0.9538	$ 0.9554	$ 0.9554	$ 0.9554	$ 0.9522	$ 0.9522	$ 0.9522	$ 0.9522	
Demand/Commodity Collections	$	469,715	$ 18,938	$ 162,308	$ 270,030	$ 63,406	$ 125,009	$ 232,436	$ 81,288	$ -	$ 1,423,130
Prior Period Reconciliation	$	(19,993)	$ (806)	$ (6,897)	$ (11,475)	$ (2,694)	$ (5,329)	$ (9,909)	$ (3,466)	$ -	$ (60,570)
Working Capital Allowance	$	997	$ 40	$ 344	$ 572	$ 134	$ 266	$ 494	$ 173	$ -	$ 3,021
Bad Debt Allowance	$	2,232	$ 90	$ 770	$ 1,281	$ 301	$ 595	$ 1,106	$ 387	$ -	$ 6,762
Total Summer COG Revenues	$	452,951	$ 18,262	$ 156,525	$ 260,409	$ 61,147	$ 120,540	$ 224,127	$ 78,382	$ -	$ 1,372,343
Check		452,951	18,262	156,525	260,409	61,147	120,540	224,127	78,382	-	1,372,343

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2006 - October 2006

GAS COST RECOVERY FOR THE MONTH OF : Nov-06 Prorated

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	FOSS	Total
Sales (therms)	709,855	17,090	278,099	217,221	22,700	97,815	150,790	17,977	0	1,511,548
										1,511,548
Demand/Commodity Rate	$ 0.9891	$ 0.9891	$ 0.9907	$ 0.9907	$ 0.9907	$ 0.9875	$ 0.9875	$ 0.9875	$ 0.9875	
Prior Period Reconciliation	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	$ (0.0421)	
Working Capital Allowance	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0021	
Bad Debt Allowance	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	$ 0.0047	
Total Billed Sales Rate	$ 0.9538	$ 0.9538	$ 0.9554	$ 0.9554	$ 0.9554	$ 0.9522	$ 0.9522	$ 0.9522	$ 0.9522	
Demand/Commodity Collections	$ 702,118	$ 16,903	$ 275,513	$ 215,201	$ 22,488	$ 96,593	$ 148,905	$ 17,752	$ -	$ 1,495,474
Prior Period Reconciliation	$ (29,885)	$ (719)	$ (11,708)	$ (9,145)	$ (956)	$ (4,118)	$ (6,348)	$ (757)	$ -	$ (63,636)
Working Capital Allowance	$ 1,491	$ 36	$ 584	$ 456	$ 48	$ 205	$ 317	$ 38	$ -	$ 3,174
Bad Debt Allowance	$ 3,336	$ 80	$ 1,307	$ 1,021	$ 107	$ 460	$ 709	$ 84	$ -	$ 7,104
Total Summer COG Revenues	$ 677,060	$ 16,300	$ 265,696	$ 207,533	$ 21,687	$ 93,140	$ 143,582	$ 17,118	$ -	$ 1,442,116
Check	677,060	16,300	265,696	207,533	21,687	93,140	143,582	17,118	-	1,442,116

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006-07 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2006 - April 2007

GAS COST RECOVERY FOR THE MONTH OF : **November 2006 (Prorated)**

	Res. Heat & NH	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	318,072	6,312	51,710	192,935	166,158	374,829	83,264	106,376	176,993	1,476,648
										1,299,655
										1,299,655
Demand/Commodity Rate	$ 1.2235	$ 1.2235	$ 1.2216	$ 1.2370	$ 1.2216	$ 1.2370	$ 1.2216	$ 1.2370		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.2984	$ 1.2984	$ 1.2965	$ 1.3119	$ 1.2965	$ 1.3119	$ 1.2965	$ 1.3119		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 389,161	$ 7,723	$ 63,168	$ 238,660	$ 202,978	$ 463,663	$ 101,715	$ 131,588		$ 1,598,657
Prior Period Reconciliation	$ 21,406	$ 425	$ 3,480	$ 12,985	$ 11,182	$ 25,226	$ 5,604	$ 7,159		$ 87,467
Working Captal Allowance	$ 700	$ 14	$ 114	$ 424	$ 366	$ 825	$ 183	$ 234		$ 2,859
Bad Debt Allowance	$ 1,718	$ 34	$ 279	$ 1,042	$ 897	$ 2,024	$ 450	$ 574		$ 7,018
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Total Billed Rate	$ 412,984	$ 8,196	$ 67,041	$ 253,111	$ 215,424	$ 491,738	$ 107,952	$ 139,555		$ 1,696,001
	$ 412,984	$ 8,196	$ 67,041	$ 253,111	$ 215,424	$ 491,738	$ 107,952	$ 139,555		$ 1,696,001
Check	$ 412,984		$ 67,041	$ 253,111	$ 215,424	$ 491,738	$ 107,952	$ 139,555		$ 1,687,805
Capacity Reserve Charge-Transportation									$ 973	$ 1,696,975

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006-07 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2006 - April 2007

GAS COST RECOVERY FOR THE MONTH OF : December 2006 (old)

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	945,447	18,699	100,232	425,708	140,748	256,567	13,433	19,859	1,191,380	3,112,074
										1,920,694
										1,920,694
Demand/Commodity Rate	$ 1.2235	$ 1.2235	$ 1.2216	$ 1.2370	$ 1.2216	$ 1.2370	$ 1.2216	$ 1.2370		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.2984	$ 1.2984	$ 1.2965	$ 1.3119	$ 1.2965	$ 1.3119	$ 1.2965	$ 1.3119		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 1,156,755	$ 22,878	$ 122,444	$ 526,601	$ 171,938	$ 317,374	$ 16,410	$ 24,565		$ 2,358,965
Prior Period Reconciliation	$ 63,629	$ 1,258	$ 6,746	$ 28,650	$ 9,472	$ 17,267	$ 904	$ 1,336		$ 129,263
Working Captal Allowance	$ 2,080	$ 41	$ 221	$ 937	$ 310	$ 564	$ 30	$ 44		$ 4,226
Bad Debt Allowance	$ 5,105	$ 101	$ 541	$ 2,299	$ 760	$ 1,385	$ 73	$ 107		$ 10,372
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-		$ -
Total Billed Rate	$ 1,227,569	$ 24,279	$ 129,951	$ 558,487	$ 182,480	$ 336,591	$ 17,416	$ 26,053		$ 2,502,825
	$ 1,227,569	$ 24,279	$ 129,951	$ 558,487	$ 182,480	$ 336,591	$ 17,416	$ 26,053		$ 2,502,825
Check	$ 1,227,569		$ 129,951	$ 558,487	$ 182,480	$ 336,591	$ 17,416	$ 26,053		$ 2,478,545
Capacity Reserve Charge-Transportation									$ 6,553	$ 2,509,377

GAS COST RECOVERY FOR THE MONTH OF : December 2006 (new)

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	541,405	7,392	52,353	322,174	164,218	488,716	64,007	114,657	237,938	1,992,859
										1,754,921
										1,754,921
Demand/Commodity Rate	$ 1.2510	$ 1.2510	$ 1.2491	$ 1.2645	$ 1.2491	$ 1.2645	$ 1.2491	$ 1.2645		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.3259	$ 1.3259	$ 1.3240	$ 1.3394	$ 1.3240	$ 1.3394	$ 1.3240	$ 1.3394		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 677,298	$ 9,247	$ 65,394	$ 407,389	$ 205,125	$ 617,981	$ 79,951	$ 144,984		$ 2,207,368
Prior Period Reconciliation	$ 36,437	$ 497	$ 3,523	$ 21,682	$ 11,052	$ 32,891	$ 4,308	$ 7,716		$ 118,106
Working Captal Allowance	$ 1,191	$ 16	$ 115	$ 709	$ 361	$ 1,075	$ 141	$ 252		$ 3,861
Bad Debt Allowance	$ 2,924	$ 40	$ 283	$ 1,740	$ 887	$ 2,639	$ 346	$ 619		$ 9,477
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-		$ -
Total Billed Rate	$ 717,849	$ 9,801	$ 69,315	$ 431,520	$ 217,425	$ 654,586	$ 84,745	$ 153,572		$ 2,338,812
	$ 717,849	$ 9,801	$ 69,315	$ 431,520	$ 217,425	$ 654,586	$ 84,745	$ 153,572		$ 2,338,812
Check	$ 717,849		$ 69,315	$ 431,520	$ 217,425	$ 654,586	$ 84,745	$ 153,572	$ 1,309	$ 2,330,319

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006-07 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2006 - April 2007

GAS COST RECOVERY FOR THE MONTH OF : January 2007 (old)

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	1,528,138	22,937	118,831	760,691	170,957	466,033	19,635	46,200	1,533,093	4,666,514
										3,133,421
										3,133,421
Demand/Commodity Rate	$ 1.2510	$ 1.2510	$ 1.2491	$ 1.2645	$ 1.2491	$ 1.2645	$ 1.2491	$ 1.2645		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.3259	$ 1.3259	$ 1.3240	$ 1.3394	$ 1.3240	$ 1.3394	$ 1.3240	$ 1.3394		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 1,911,700	$ 28,694	$ 148,431	$ 961,894	$ 213,542	$ 589,299	$ 24,526	$ 58,420		$ 3,936,506
Prior Period Reconciliation	$ 102,844	$ 1,544	$ 7,997	$ 51,194	$ 11,505	$ 31,364	$ 1,321	$ 3,109		$ 210,879
Working Captal Allowance	$ 3,362	$ 50	$ 261	$ 1,674	$ 376	$ 1,025	$ 43	$ 102		$ 6,894
Bad Debt Allowance	$ 8,252	$ 124	$ 642	$ 4,108	$ 923	$ 2,517	$ 106	$ 249		$ 16,920
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Total Billed Rate	$ 2,026,158	$ 30,412	$ 157,332	$ 1,018,869	$ 226,347	$ 624,204	$ 25,996	$ 61,881		$ 4,171,199
	$ 2,026,158	$ 30,412	$ 157,332	$ 1,018,869	$ 226,347	$ 624,204	$ 25,996	$ 61,881		$ 4,171,199
Check	$ 2,026,158	$ 30,412	$ 157,332	$ 1,018,869	$ 226,347	$ 624,204	$ 25,996	$ 61,881		$ 4,171,199
Capacity Reserve Charge-Transportation									$ 8,432	$ 4,179,631

GAS COST RECOVERY FOR THE MONTH OF : January 2007 (new)

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	565,493	9,168	74,511	433,505	197,649	685,882	65,615	156,637	322,335	2,510,796
										2,188,461
										2,188,461
Demand/Commodity Rate	$ 1.0880	$ 1.0880	$ 1.0861	$ 1.1015	$ 1.0861	$ 1.1015	$ 1.0861	$ 1.1015		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.1629	$ 1.1629	$ 1.1610	$ 1.1764	$ 1.1610	$ 1.1764	$ 1.1610	$ 1.1764		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 615,257	$ 9,975	$ 80,927	$ 477,506	$ 214,667	$ 755,499	$ 71,265	$ 172,535		$ 2,397,630
Prior Period Reconciliation	$ 38,058	$ 617	$ 5,015	$ 29,175	$ 13,302	$ 46,160	$ 4,416	$ 10,542		$ 147,283
Working Captal Allowance	$ 1,244	$ 20	$ 164	$ 954	$ 435	$ 1,509	$ 144	$ 345		$ 4,815
Bad Debt Allowance	$ 3,054	$ 50	$ 402	$ 2,341	$ 1,067	$ 3,704	$ 354	$ 846		$ 11,818
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Total Billed Rate	$ 657,612	$ 10,662	$ 86,508	$ 509,976	$ 229,471	$ 806,872	$ 76,179	$ 184,267		$ 2,561,546
	$ 657,612	$ 10,662	$ 86,508	$ 509,976	$ 229,471	$ 806,872	$ 76,179	$ 184,267		$ 2,561,546
Check	$ 657,612	$ 10,662	$ 86,508	$ 509,976	$ 229,471	$ 806,872	$ 76,179	$ 184,267		$ 2,561,546
Capacity Reserve Charge-Transportation									$ 1,773	$ 2,563,319

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006-07 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2006 - April 2007

GAS COST RECOVERY FOR THE MONTH OF : February 2007 (old)

	Res. Heat & NH		G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	2,189,989	27,600	143,883	1,175,435	206,855	652,167	26,550	65,264	0	4,487,742
										4,487,742
										4,487,742
Demand/Commodity Rate	$ 1.0880	$ 1.0880	$ 1.0861	$ 1.1015	$ 1.0861	$ 1.1015	$ 1.0861	$ 1.1015		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.1629	$ 1.1629	$ 1.1610	$ 1.1764	$ 1.1610	$ 1.1764	$ 1.1610	$ 1.1764		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 2,382,708	$ 30,028	$ 156,272	$ 1,294,741	$ 224,665	$ 718,362	$ 28,836	$ 71,888		$ 4,907,500
Prior Period Reconciliation	$ 147,386	$ 1,857	$ 9,683	$ 79,107	$ 13,921	$ 43,891	$ 1,787	$ 4,392		$ 302,025
Working Captal Allowance	$ 4,818	$ 61	$ 317	$ 2,586	$ 455	$ 1,435	$ 58	$ 144		$ 9,873
Bad Debt Allowance	$ 11,826	$ 149	$ 777	$ 6,347	$ 1,117	$ 3,522	$ 143	$ 352		$ 24,234
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Total Billed Rate	$ 2,546,738	$ 32,095	$ 167,049	$ 1,382,781	$ 240,159	$ 767,209	$ 30,824	$ 76,776		$ 5,243,632
	$ 2,546,738	$ 32,095	$ 167,049	$ 1,382,781	$ 240,159	$ 767,209	$ 30,824	$ 76,776		$ 5,243,632
Check	$ 2,546,738	$ 32,095	$ 167,049	$ 1,382,781	$ 240,159	$ 767,209	$ 30,824	$ 76,776		$ 5,243,632
Capacity Reserve Charge-Transportation									$ -	$ 5,243,632
	$ 1,244,806									

GAS COST RECOVERY FOR THE MONTH OF : February 2007 (new)

	Res. Heat & NH		G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	950,742	10,930	82,731	697,810	219,447	919,288	86,227	224,388	2,212,856	5,404,418
										3,191,562
										3,191,562
Demand/Commodity Rate	$ 1.2110	$ 1.2110	$ 1.2091	$ 1.2245	$ 1.2091	$ 1.2245	$ 1.2091	$ 1.2245		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.2859	$ 1.2859	$ 1.2840	$ 1.2994	$ 1.2840	$ 1.2994	$ 1.2840	$ 1.2994		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 1,151,348	$ 13,236	$ 100,030	$ 854,469	$ 265,333	$ 1,125,668	$ 104,257	$ 274,762		$ 3,889,104
Prior Period Reconciliation	$ 63,985	$ 736	$ 5,568	$ 46,963	$ 14,769	$ 61,868	$ 5,803	$ 15,101		$ 214,792
Working Captal Allowance	$ 2,092	$ 24	$ 182	$ 1,535	$ 483	$ 2,022	$ 190	$ 494		$ 7,021
Bad Debt Allowance	$ 5,134	$ 59	$ 447	$ 3,768	$ 1,185	$ 4,964	$ 466	$ 1,212		$ 17,234
Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Total Billed Rate	$ 1,222,559	$ 14,054	$ 106,226	$ 906,735	$ 281,770	$ 1,194,523	$ 110,716	$ 291,569		$ 4,128,152
	$ 1,222,559	$ 14,054	$ 106,226	$ 906,735	$ 281,770	$ 1,194,523	$ 110,716	$ 291,569		$ 4,128,152
Check	$ 1,222,559	$ 14,054	$ 106,226	$ 906,735	$ 281,770	$ 1,194,523	$ 110,716	$ 291,569		$ 4,128,152
Capacity Reserve Charge-Transportation									$ 12,171	$ 4,140,323

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006-07 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2006 - April 2007

GAS COST RECOVERY FOR THE MONTH OF : March 2007 old

	Res. Heat	& NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	2,011,926	23,587	129,502	1,083,577	173,032	585,589	17,353	34,857	1,659,785	5,719,210
										4,059,425
										4,059,425
Demand/Commodity Rate	$ 1.2110	$ 1.2110	$ 1.2091	$ 1.2245	$ 1.2091	$ 1.2245	$ 1.2091	$ 1.2245		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.2859	$ 1.2859	$ 1.2840	$ 1.2994	$ 1.2840	$ 1.2994	$ 1.2840	$ 1.2994		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 2,436,443	$ 28,564	$ 156,580	$ 1,326,841	$ 209,213	$ 717,054	$ 20,982	$ 42,682	$ -	$ 4,938,360
Prior Period Reconciliation	$ 135,403	$ 1,587	$ 8,715	$ 72,925	$ 11,645	$ 39,410	$ 1,168	$ 2,346	$ -	$ 273,199
Working Captal Allowance	$ 4,426	$ 52	$ 285	$ 2,384	$ 381	$ 1,288	$ 38	$ 77	$ -	$ 8,931
Bad Debt Allowance	$ 10,864	$ 127	$ 699	$ 5,851	$ 934	$ 3,162	$ 94	$ 188	$ -	$ 21,921
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Billed Rate	$ 2,587,136	$ 30,331	$ 166,280	$ 1,408,000	$ 222,173	$ 760,915	$ 22,282	$ 45,293		$ 5,242,411
	$ 2,587,136	$ 30,331	$ 166,280	$ 1,408,000	$ 222,173	$ 760,915	$ 22,282	$ 45,293		$ 5,242,411
	$ 2,587,136	$ 30,331	$ 166,280	$ 1,408,000	$ 222,173	$ 760,915	$ 22,282	$ 45,293		$ 5,242,411
Capacity Reserve Charge-Transportation									$ 9,129	

GAS COST RECOVERY FOR THE MONTH OF : March 2007 new

	Res. Heat	& NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
GAS COST RECOVERY FOR THE MONTH OF :	863,459	11,885	92,677	585,068	197,799	813,461	88,746	159,071	387,509	3,199,672
										2,812,164
										2,812,164
Demand/Commodity Rate	$ 1.4832	$ 1.4832	$ 1.4809	$ 1.4963	$ 1.4809	$ 1.4963	$ 1.4809	$ 1.4963		
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.5581	$ 1.5581	$ 1.5558	$ 1.5712	$ 1.5558	$ 1.5712	$ 1.5558	$ 1.5712		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 1,280,682	$ 17,627	$ 137,245	$ 875,437	$ 292,920	$ 1,217,181	$ 131,423	$ 238,018	$ -	$ 4,190,533
Prior Period Reconciliation	$ 58,111	$ 800	$ 6,237	$ 39,375	$ 13,312	$ 54,746	$ 5,973	$ 10,705	$ -	$ 189,259
Working Captal Allowance	$ 1,900	$ 26	$ 204	$ 1,287	$ 435	$ 1,790	$ 195	$ 350	$ -	$ 6,187
Bad Debt Allowance	$ 4,663	$ 64	$ 500	$ 3,159	$ 1,068	$ 4,393	$ 479	$ 859	$ -	$ 15,186
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Billed Rate	$ 1,345,355	$ 18,517	$ 144,186	$ 919,258	$ 307,735	$ 1,278,109	$ 138,070	$ 249,932	$ -	$ 4,401,164
	$ 1,345,355	$ 18,517	$ 144,186	$ 919,258	$ 307,735	$ 1,278,109	$ 138,070	$ 249,932	$ -	$ 4,401,164
Capacity Reserve Charge-Transportation									$ 2,131	

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006-07 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2006 - April 2007

GAS COST RECOVERY FOR THE MONTH OF : **April 2007**

	Res. Heat	& NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	1,939,742	30,582	176,401	1,042,756	292,068	866,506	79,670	135,430	2,074,484	6,637,639
										4,563,155
Demand/Commodity Rate	$ 1.4832	$ 1.4832	$ 1.4809	$ 1.4963	$ 1.4809	$ 1.4963	$ 1.4809	$ 1.4963		4,563,155
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.5581	$ 1.5581	$ 1.5558	$ 1.5712	$ 1.5558	$ 1.5712	$ 1.5558	$ 1.5712		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 2,877,025	$ 45,359	$ 261,232	$ 1,560,276	$ 432,524	$ 1,296,553	$ 117,983	$ 202,644	$ -	$ 6,793,596
Prior Period Reconciliation	$ 130,545	$ 2,058	$ 11,872	$ 70,177	$ 19,656	$ 58,316	$ 5,362	$ 9,114	$ -	$ 307,100
Working Captal Allowance	$ 4,267	$ 67	$ 388	$ 2,294	$ 643	$ 1,906	$ 175	$ 298	$ -	$ 10,039
Bad Debt Allowance	$ 10,475	$ 165	$ 953	$ 5,631	$ 1,577	$ 4,679	$ 430	$ 731	$ -	$ 24,641
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Billed Rate	$ 3,022,312	$ 47,650	$ 274,445	$ 1,638,378	$ 454,399	$ 1,361,454	$ 123,951	$ 212,788	$ -	$ 7,135,377
Capacity Reserve Charge-Transportation										
	$ 3,022,312	$ 47,650	$ 274,445	$ 1,638,378	$ 454,399	$ 1,361,454	$ 123,951	$ 212,788	$ 11,410	$ 7,146,786

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2006-07 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2006 - April 2007

GAS COST RECOVERY FOR THE MONTH OF : May 2007 (Prorated)

	Res Heat and NH		G-50	G-40	G-51	G-41	G-52	G-42		Total
Demand/Commodity Rate	959,171	17,940	100,440	417,727	118,494	250,354	12,805	14,439	1,461,246	3,352,615
										3,352,615
Demand/Commodity Rate	$ 1.4832	$ 1.4832	$ 1.4809	$ 1.4963	$ 1.4809	$ 1.4963	$ 1.4809	$ 1.4963		1,891,370
Prior Period Reconciliation	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673	$ 0.0673		
Working Captal Allowance	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022		
Bad Debt Allowance	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054		
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Billed Rate	$ 1.5581	$ 1.5581	$ 1.5558	$ 1.5712	$ 1.5558	$ 1.5712	$ 1.5558	$ 1.5712		
Capacity Reserve Charge-Transportation									$ 0.0055	
Demand/Commodity Rate	$ 1,422,643	$ 26,608	$ 148,741	$ 625,045	$ 175,478	$ 374,605	$ 18,963	$ 21,606	$ -	$ 2,813,687
Prior Period Reconciliation	$ 64,552	$ 1,207	$ 6,760	$ 28,113	$ 7,975	$ 16,849	$ 862	$ 972	$ -	$ 127,289
Working Captal Allowance	$ 2,110	$ 39	$ 221	$ 919	$ 261	$ 551	$ 28	$ 32	$ -	$ 4,161
Bad Debt Allowance	$ 5,180	$ 97	$ 542	$ 2,256	$ 640	$ 1,352	$ 69	$ 78	$ -	$ 10,213
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Billed Rate	$ 1,494,485	$ 27,952	$ 156,264	$ 656,332	$ 184,353	$ 393,356	$ 19,922	$ 22,687	$ -	$ 2,955,351
Capacity Reserve Charge-Transportation										
	$ 1,494,485	$ 27,952	$ 156,264	$ 656,332	$ 184,353	$ 393,356	$ 19,922	$ 22,687	$ 8,037	$ 2,963,388

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2007 - October 2007

FORM III
Schedule 3
Page 2 of 8

GAS COST RECOVERY FOR THE MONTH OF : May-07 Prorated

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	231,190	7,629	119,517	173,989	45,494	56,500	120,781	54,822	151,748	961,669
									Sales Volumes	809,920
Demand/Commodity Rate	$ 0.9550	$ 0.9550	$ 1.0033	$ 1.0033	$ 1.0033	$ 0.9066	$ 0.9066	$ 0.9066	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.9040	$ 0.9040	$ 0.9523	$ 0.9523	$ 0.9523	$ 0.8556	$ 0.8556	$ 0.8556	$ -	
Capacity Reserve Charge									$ 0.0055	
Recovery Revenues										
Demand/Commodity Collections	$ 220,786	$ 7,285	$ 119,912	$ 174,563	$ 45,644	$ 51,222	$ 109,500	$ 49,701	$ -	$ 778,614
Prior Period Reconciliation	$ (12,900)	$ (426)	$ (6,669)	$ (9,709)	$ (2,539)	$ (3,153)	$ (6,740)	$ (3,059)	$ -	$ (45,194)
Working Capital Allowance	$ 324	$ 11	$ 167	$ 244	$ 64	$ 79	$ 169	$ 77	$ -	$ 1,134
Bad Debt Allowance	$ 786	$ 26	$ 406	$ 592	$ 155	$ 192	$ 411	$ 186	$ -	$ 2,754
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 835	$ 835
Total Summer COG Revenues	$ 208,995	$ 6,896	$ 113,816	$ 165,690	$ 43,324	$ 48,341	$ 103,340	$ 46,906	$ 835	$ 738,143
Check (Total billed sales rate * Therms)	208,995	6,896	113,816	165,690	43,324	48,341	103,340	46,906	835	738,143

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2007 - October 2007

GAS COST RECOVERY FOR THE MONTH OF : Jun-07

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	566,640	22,874	191,834	219,785	12,756	140,788	212,028	76,326	1,222,391	2,665,422
									Sales Volumes	1,443,031
Demand/Commodity Rate	$ 0.9550	$ 0.9550	$ 1.0033	$ 1.0033	$ 1.0033	$ 0.9066	$ 0.9066	$ 0.9066	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.9040	$ 0.9040	$ 0.9523	$ 0.9523	$ 0.9523	$ 0.8556	$ 0.8556	$ 0.8556	$ -	
Capacity Reserve Charge									$ 0.0055	
Recovery Revenues										
Demand/Commodity Collections	$ 541,141	$ 21,845	$ 192,467	$ 220,510	$ 12,798	$ 127,638	$ 192,225	$ 69,197	$ -	$ 1,377,821
Prior Period Reconciliation	$ (31,619)	$ (1,276)	$ (10,704)	$ (12,264)	$ (712)	$ (7,856)	$ (11,831)	$ (4,259)	$ -	$ (80,521)
Working Capital Allowance	$ 793	$ 32	$ 269	$ 308	$ 18	$ 197	$ 297	$ 107	$ -	$ 2,020
Bad Debt Allowance	$ 1,927	$ 78	$ 652	$ 747	$ 43	$ 479	$ 721	$ 260	$ -	$ 4,906
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,723	$ 6,723
Total Summer COG Revenues	$ 512,243	$ 20,678	$ 182,684	$ 209,301	$ 12,148	$ 120,458	$ 181,411	$ 65,305	$ 6,723	$ 1,310,950
Check (Total billed sales rate * Therms)	$ 512,243	$ 20,678	$ 182,684	$ 209,301	$ 12,148	$ 120,458	$ 181,411	$ 65,305	$ 6,723	1,310,950

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2007 - October 2007

GAS COST RECOVERY FOR THE MONTH OF : Jul-07 (Old)

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	262,344	14,295	69,390	65,720	3,377	101,747	99,148	10,682	1,080,873	1,707,575
									Sales Volumes	626,703
Demand/Commodity Rate	$ 0.9550	$ 0.9550	$ 1.0033	$ 1.0033	$ 1.0033	$ 0.9066	$ 0.9066	$ 0.9066	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.9040	$ 0.9040	$ 0.9523	$ 0.9523	$ 0.9523	$ 0.8556	$ 0.8556	$ 0.8556	$ -	
Capacity Reserve Charge									$ 0.0055	
Recovery Revenues										
Demand/Commodity Collections	$ 250,538	$ 13,652	$ 69,619	$ 65,937	$ 3,388	$ 92,243	$ 89,888	$ 9,684	$ -	$ 594,950
Prior Period Reconciliation	$ (14,639)	$ (798)	$ (3,872)	$ (3,667)	$ (188)	$ (5,677)	$ (5,532)	$ (596)	$ -	$ (34,970)
Working Capital Allowance	$ 367	$ 20	$ 97	$ 92	$ 5	$ 142	$ 139	$ 15	$ -	$ 877
Bad Debt Allowance	$ 892	$ 49	$ 236	$ 223	$ 11	$ 346	$ 337	$ 36	$ -	$ 2,131
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,945	$ 5,945
Total Summer COG Revenues	$ 237,159	$ 12,923	$ 66,080	$ 62,585	$ 3,216	$ 87,054	$ 84,831	$ 9,139	$ 5,945	$ 568,933
Check (Total billed sales rate * Therms)	$ 237,159	$ 12,923	$ 66,080	$ 62,585	$ 3,216	$ 87,054	$ 84,831	$ 9,139	$ -	562,988

GAS COST RECOVERY FOR THE MONTH OF : Jul-07 (New)

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	117,228	6,117	40,022	79,738	19,739	50,832	122,007	76,941	105,432	618,055
									Sales Volumes	512,623
Demand/Commodity Rate	$ 0.8950	$ 0.8950	$ 0.9433	$ 0.9433	$ 0.9433	$ 0.8466	$ 0.8466	$ 0.8466	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.8440	$ 0.8440	$ 0.8923	$ 0.8923	$ 0.8923	$ 0.7956	$ 0.7956	$ 0.7956	$ -	
Capacity Reserve Charge									$ 0.0055	
Recovery Revenues										
Demand/Commodity Collections	$ 104,919	$ 5,475	$ 37,752	$ 75,217	$ 18,620	$ 43,034	$ 103,291	$ 65,139	$ -	$ 453,446
Prior Period Reconciliation	$ (6,541)	$ (341)	$ (2,233)	$ (4,449)	$ (1,101)	$ (2,836)	$ (6,808)	$ (4,293)	$ -	$ (28,604)
Working Capital Allowance	$ 164	$ 9	$ 56	$ 112	$ 28	$ 71	$ 171	$ 108	$ -	$ 718
Bad Debt Allowance	$ 399	$ 21	$ 136	$ 271	$ 67	$ 173	$ 415	$ 262	$ -	$ 1,743
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 580	$ 580
Total Summer COG Revenues	$ 98,941	$ 5,163	$ 35,711	$ 71,150	$ 17,613	$ 40,442	$ 97,069	$ 61,214	$ 580	$ 427,882
Check (Total billed sales rate * Therms)	$ 98,941	$ 5,163	$ 35,711	$ 71,150	$ 17,613	$ 40,442	$ 97,069	$ 61,214	$ -	427,303

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2007 - October 2007

GAS COST RECOVERY FOR THE MONTH OF : Aug-07

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	328,130	19,444	87,213	116,320	15,728	146,712	194,758	85,967	1,185,676	2,179,948
									Sales Volumes	994,272
Demand/Commodity Rate	$ 0.8950	$ 0.8950	$ 0.9433	$ 0.9433	$ 0.9433	$ 0.8466	$ 0.8466	$ 0.8466	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.8440	$ 0.8440	$ 0.8923	$ 0.8923	$ 0.8923	$ 0.7956	$ 0.7956	$ 0.7956	$ -	
Capacity Reserve Charge									$ 0.0055	
Recovery Revenues										
Demand/Commodity Collections	$ 293,676	$ 17,402	$ 82,268	$ 109,725	$ 14,836	$ 124,206	$ 164,882	$ 72,780	$ -	$ 879,776
Prior Period Reconciliation	$ (18,310)	$ (1,085)	$ (4,866)	$ (6,491)	$ (878)	$ (8,187)	$ (10,867)	$ (4,797)	$ -	$ (55,480)
Working Capital Allowance	$ 459	$ 27	$ 122	$ 163	$ 22	$ 205	$ 273	$ 120	$ -	$ 1,392
Bad Debt Allowance	$ 1,116	$ 66	$ 297	$ 395	$ 53	$ 499	$ 662	$ 292	$ -	$ 3,381
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,521	$ 6,521
Total Summer COG Revenues	$ 276,942	$ 16,411	$ 77,820	$ 103,792	$ 14,034	$ 116,724	$ 154,949	$ 68,395	$ 6,521	$ 835,589
Check (Total billed sales rate * Therms)	$ 276,942	$ 16,411	$ 77,820	$ 103,792	$ 14,034	$ 116,724	$ 154,949	$ 68,395	$ 6,521	835,589

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2007 - October 2007

GAS COST RECOVERY FOR THE MONTH OF : Sep-07 Old

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	250,041	14,298	70,305	59,090	6,335	105,533	94,562	13,178	1,184,875	1,798,216
									Sales Volumes	613,341
Demand/Commodity Rate	$ 0.8950	$ 0.8950	$ 0.9433	$ 0.9433	$ 0.9433	$ 0.8466	$ 0.8466	$ 0.8466	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.8440	$ 0.8440	$ 0.8923	$ 0.8923	$ 0.8923	$ 0.7956	$ 0.7956	$ 0.7956	$ -	
Capacity Reserve Charge									$ 0.0055	
Demand/Commodity Collections	$ 223,787	$ 12,796	$ 66,319	$ 55,739	$ 5,975	$ 89,344	$ 80,056	$ 11,157	$ -	$ 545,173
Prior Period Reconciliation	$ (13,952)	$ (798)	$ (3,923)	$ (3,297)	$ (353)	$ (5,889)	$ (5,277)	$ (735)	$ -	$ (34,224)
Working Capital Allowance	$ 350	$ 20	$ 98	$ 83	$ 9	$ 148	$ 132	$ 18	$ -	$ 859
Bad Debt Allowance	$ 850	$ 49	$ 239	$ 201	$ 22	$ 359	$ 322	$ 45	$ -	$ 2,085
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,517	$ 6,517
Total Summer COG Revenues	$ 211,035	$ 12,067	$ 62,733	$ 52,726	$ 5,652	$ 83,962	$ 75,233	$ 10,484	$ 6,517	$ 520,410
Check (Total billed sales rate * Therms)	$ 211,035	$ 12,067	$ 62,733	$ 52,726	$ 5,652	$ 83,962	$ 75,233	$ 10,484	$ 6,517	520,410

GAS COST RECOVERY FOR THE MONTH OF : Sep-07 New

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	116,997	6,101	43,510	72,629	34,577	50,220	102,315	73,561	114,604	614,514
									Sales Volumes	499,910
Demand/Commodity Rate	$ 0.7742	$ 0.7742	$ 0.8225	$ 0.8225	$ 0.8225	$ 0.7355	$ 0.7355	$ 0.7355	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.7232	$ 0.7232	$ 0.7715	$ 0.7715	$ 0.7715	$ 0.6845	$ 0.6845	$ 0.6845	$ -	
Capacity Reserve Charge									$ 0.0055	
Demand/Commodity Collections	$ 90,579	$ 4,723	$ 35,787	$ 59,738	$ 28,440	$ 36,937	$ 75,253	$ 54,104	$ -	$ 385,560
Prior Period Reconciliation	$ (6,528)	$ (340)	$ (2,428)	$ (4,053)	$ (1,929)	$ (2,802)	$ (5,709)	$ (4,105)	$ -	$ (27,895)
Working Capital Allowance	$ 164	$ 9	$ 61	$ 102	$ 48	$ 70	$ 143	$ 103	$ -	$ 700
Bad Debt Allowance	$ 398	$ 21	$ 148	$ 247	$ 118	$ 171	$ 348	$ 250	$ -	$ 1,700
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 630	$ 630
Total Summer COG Revenues	$ 84,612	$ 4,412	$ 33,568	$ 56,034	$ 26,676	$ 34,375	$ 70,035	$ 50,352	$ 630.32	$ 360,695
Check (Total billed sales rate * Therms)	$ 84,612	$ 4,412	$ 33,568	$ 56,034	$ 26,676	$ 34,375	$ 70,035	$ 50,352	$ 630	360,695

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2007 - October 2007

GAS COST RECOVERY FOR THE MONTH OF : Oct-07

	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
Sales (therms)	380,717	17,359	135,482	214,835	26,282	117,154	199,524	85,535	1,493,702	2,670,590
									Sales Volumes	1,176,888
Demand/Commodity Rate	$ 0.7742	$ 0.7742	$ 0.8225	$ 0.8225	$ 0.8225	$ 0.7355	$ 0.7355	$ 0.7355	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.7232	$ 0.7232	$ 0.7715	$ 0.7715	$ 0.7715	$ 0.6845	$ 0.6845	$ 0.6845	$ -	
Capacity Reserve Charge									$ 0.0055	
Demand/Commodity Collections	$ 294,751	$ 13,439	$ 111,434	$ 176,702	$ 21,617	$ 86,167	$ 146,750	$ 62,911	$ -	$ 913,771
Prior Period Reconciliation	$ (21,244)	$ (969)	$ (7,560)	$ (11,988)	$ (1,467)	$ (6,537)	$ (11,133)	$ (4,773)	$ -	$ (65,670)
Working Capital Allowance	$ 533	$ 24	$ 190	$ 301	$ 37	$ 164	$ 279	$ 120	$ -	$ 1,648
Bad Debt Allowance	$ 1,294	$ 59	$ 461	$ 730	$ 89	$ 398	$ 678	$ 291	$ -	$ 4,001
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,215	$ 8,215
Total Summer COG Revenues	$ 275,335	$ 12,554	$ 104,524	$ 165,745	$ 20,277	$ 80,192	$ 136,574	$ 58,549	$ 8,215	$ 861,965
Check (Total billed sales rate * Therms)	$ 275,335	$ 12,554	$ 104,524	$ 165,745	$ 20,277	$ 80,192	$ 136,574	$ 58,549	$ 8,215	861,965

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2007 - October 2007

FORM III
Schedule 3
Page 8 of 8

GAS COST RECOVERY FOR THE MONTH OF :	Res. Heat	Res. NH	G-40	G-41	G-42	G-50	G-51	G-52	Transportation	Total
		Nov-07	Prorated							
Sales (therms)	494,173	15,758	185,650	156,722	14,968	83,115	113,792	10,673	1,603,257	2,678,108
									Sales Volumes	1,074,851
Demand/Commodity Rate	$ 0.7742	$ 0.7742	$ 0.8225	$ 0.8225	$ 0.8225	$ 0.7355	$ 0.7355	$ 0.7355	$ -	
Prior Period Reconciliation	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ (0.0558)	$ -	
Working Capital Allowance	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ -	
Bad Debt Allowance	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$ -	
Total Billed Sales Rate	$ 0.7232	$ 0.7232	$ 0.7715	$ 0.7715	$ 0.7715	$ 0.6845	$ 0.6845	$ 0.6845	$ -	
Capacity Reserve Charge									$ 0.0055	
Demand/Commodity Collections	$ 382,589	$ 12,200	$ 152,697	$ 128,904	$ 12,311	$ 61,131	$ 83,694	$ 7,850	$ -	$ 841,376
Prior Period Reconciliation	$ (27,575)	$ (879)	$ (10,359)	$ (8,745)	$ (835)	$ (4,638)	$ (6,350)	$ (596)	$ -	$ (59,977)
Working Capital Allowance	$ 692	$ 22	$ 260	$ 219	$ 21	$ 116	$ 159	$ 15	$ -	$ 1,505
Bad Debt Allowance	$ 1,680	$ 54	$ 631	$ 533	$ 51	$ 283	$ 387	$ 36	$ -	$ 3,654
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,818	$ 8,818
Total Summer COG Revenues	$ 357,386	$ 11,396	$ 143,229	$ 120,911	$ 11,548	$ 56,892	$ 77,890	$ 7,305	$ 8,818	$ 795,376
Check (Total billed sales rate * Therms)	$ 357,386	$ 11,396	$ 143,229	$ 120,911	$ 11,548	$ 56,892	$ 77,890	$ 7,305	$ 8,818	795,376

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

FORM III
Schedule 3
Page 2 of 8

GAS COST RECOVERY FOR THE MONTH OF :			November 2007	Prorated						
	Res. Heat & NH	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	412,340	6,373	46,653	225,794	124,644	381,697	68,059	78,963	280,094	1,624,616
										1,624,616
									Sales	1,344,521
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Revenues										
Demand & Commodity	$ 466,521	$ 7,210	$ 49,009	$ 270,795	$ 130,938	$ 457,769	$ 71,495	$ 94,701	$ -	$ 1,548,438
Prior Period Reconciliation	$ (31,420)	$ (486)	$ (3,555)	$ (17,206)	$ (9,498)	$ (29,085)	$ (5,186)	$ (6,017)	$ -	$ (102,453)
Working Captal Allowance	$ 742	$ 11	$ 84	$ 406	$ 224	$ 687	$ 123	$ 142	$ -	$ 2,420
Supplier Refund	$ (206)	$ (3)	$ (23)	$ (113)	$ (62)	$ (191)	$ (34)	$ (39)	$ -	$ (672)
Bad Debt Allowance	$ 1,856	$ 29	$ 210	$ 1,016	$ 561	$ 1,718	$ 306	$ 355	$ -	$ 6,050
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,543	$ 1,543
Total Peak COG Revenues	$ 437,493	$ 6,761	$ 45,725	$ 254,899	$ 122,163	$ 430,897	$ 66,704	$ 89,142	$ 1,543	$ 1,455,327
Check (Total Billed Sales Rate * Therms)	$ 437,493	$ 6,761	$ 45,725	$ 254,899	$ 122,163	$ 430,897	$ 66,704	$ 89,142	$ 1,543	$ 1,455,327

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : December 2007	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	2,168,421	32,147	170,253	1,186,009	329,251	1,085,168	105,113	171,477	744,653	5,992,492
										7,472,553
									Sales	5,247,839
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 2,453,352	$ 36,371	$ 178,851	$ 1,422,381	$ 345,878	$ 1,301,442	$ 110,421	$ 205,652	$ -	$ 6,054,348
Prior Period Reconciliation	$ (165,234)	$ (2,450)	$ (12,973)	$ (90,374)	$ (25,089)	$ (82,690)	$ (8,010)	$ (13,067)	$ -	$ (399,885)
Working Captal Allowance	$ 3,903	$ 58	$ 306	$ 2,135	$ 593	$ 1,953	$ 189	$ 309	$ -	$ 9,446
Supplier Refund	$ (1,084)	$ (16)	$ (85)	$ (593)	$ (165)	$ (543)	$ (53)	$ (86)	$ -	$ (2,624)
Bad Debt Allowance	$ 9,758	$ 145	$ 766	$ 5,337	$ 1,482	$ 4,883	$ 473	$ 772	$ -	$ 23,615
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,103	$ 4,103
Total Peak COG Revenues	$ 2,300,695	$ 34,108	$ 166,865	$ 1,338,886	$ 322,699	$ 1,225,046	$ 103,021	$ 193,580	$ 4,103	$ 5,689,003
Check (Total Billed Sales Rate * Therms)	2,300,695	34,108	166,865	1,338,886	322,699	1,225,046	103,021	193,580	4,103	5,689,003

FORM III
Schedule 3
Page 4 of 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : January 2008

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	2,744,489	35,421	230,580	1,531,133	359,149	1,239,744	71,163	130,441	894,482	7,236,602
										9,176,920
Peak Period Demand/Commodity Recovery Rate									Sales	6,342,120
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 3,105,115	$ 40,075	$ 242,224	$ 1,836,288	$ 377,286	$ 1,486,825	$ 74,757	$ 156,438	$ -	$ 7,319,008
Prior Period Reconciliation	$ (209,130)	$ (2,699)	$ (17,570)	$ (116,672)	$ (27,367)	$ (94,468)	$ (5,423)	$ (9,940)	$ -	$ (483,270)
Working Captal Allowance	$ 4,940	$ 64	$ 415	$ 2,756	$ 646	$ 2,232	$ 128	$ 235	$ -	$ 11,416
Supplier Refund	$ (1,372)	$ (18)	$ (115)	$ (766)	$ (180)	$ (620)	$ (36)	$ (65)	$ -	$ (3,171)
Bad Debt Allowance	$ 12,350	$ 159	$ 1,038	$ 6,890	$ 1,616	$ 5,579	$ 320	$ 587	$ -	$ 28,540
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,929	$ 4,929
Total Peak COG Revenues	$ 2,911,903	$ 37,582	$ 225,991	$ 1,728,496	$ 352,002	$ 1,399,547	$ 69,747	$ 147,255	$ 4,929	$ 6,877,451
Check (Total Billed Sales Rate * Therms)	$ 2,911,903	$ 37,582	$ 225,991	$ 1,728,496	$ 352,002	$ 1,399,547	$ 69,747	$ 147,255	$ 4,929	$ 6,877,451

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : Febrauary 2008

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	2,635,399	32,354	184,239	1,482,788	356,649	1,170,606	58,677	167,483	903,698	6,991,893
										8,793,148
									Sales	6,088,195
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 2,981,690	$ 36,605	$ 193,543	$ 1,778,308	$ 374,660	$ 1,403,908	$ 61,640	$ 200,862	$ -	$ 7,031,217
Prior Period Reconciliation	$ (200,817)	$ (2,465)	$ (14,039)	$ (112,988)	$ (27,177)	$ (89,200)	$ (4,471)	$ (12,762)	$ -	$ (463,920)
Working Captal Allowance	$ 4,744	$ 58	$ 332	$ 2,669	$ 642	$ 2,107	$ 106	$ 301	$ -	$ 10,959
Supplier Refund	$ (1,318)	$ (16)	$ (92)	$ (741)	$ (178)	$ (585)	$ (29)	$ (84)	$ -	$ (3,044)
Bad Debt Allowance	$ 11,859	$ 146	$ 829	$ 6,673	$ 1,605	$ 5,268	$ 264	$ 754	$ -	$ 27,397
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,979	$ 4,979
Total Peak COG Revenues	**$ 2,796,158**	**$ 34,328**	**$ 180,573**	**$ 1,673,919**	**$ 349,552**	**$ 1,321,497**	**$ 57,509**	**$ 189,072**	**$ 4,979**	**$ 6,607,587**
Check (Total Billed Sales Rate * Therms)	$ 2,796,158	$ 34,328	$ 180,573	$ 1,673,919	$ 349,552	$ 1,321,497	$ 57,509	$ 189,072	$ 4,979	$ 6,607,587

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

FORM III
Schedule 3
Page 6 of 8

GAS COST RECOVERY FOR THE MONTH OF : March 2008

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (therms)	2,496,732	31,078	183,359	1,369,487	326,982	1,120,681	56,596	138,979	813,941	6,537,835
										8,444,432
Peak Period Demand/Commodity Recovery Rate									Sales	5,723,894
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 2,824,803	$ 35,162	$ 192,619	$ 1,642,426	$ 343,495	$ 1,344,033	$ 59,454	$ 166,678	$ -	$ 6,608,668
Prior Period Reconciliation	$ (190,251)	$ (2,368)	$ (13,972)	$ (104,355)	$ (24,916)	$ (85,396)	$ (4,313)	$ (10,590)	$ -	$ (436,161)
Working Captal Allowance	$ 4,494	$ 56	$ 330	$ 2,465	$ 589	$ 2,017	$ 102	$ 250	$ -	$ 10,303
Supplier Refund	$ (1,248)	$ (16)	$ (92)	$ (685)	$ (163)	$ (560)	$ (28)	$ (69)	$ -	$ (2,862)
Bad Debt Allowance	$ 11,235	$ 140	$ 825	$ 6,163	$ 1,471	$ 5,043	$ 255	$ 625	$ -	$ 25,758
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,485	$ 4,485
Total Peak COG Revenues	$ 2,649,033	$ 32,974	$ 179,710	$ 1,546,014	$ 320,475	$ 1,265,137	$ 55,470	$ 156,893	$ 4,485	$ 6,210,190
Check (Total Billed Sales Rate * Therms)	$ 2,649,033	$ 32,974	$ 179,710	$ 1,546,014	$ 320,475	$ 1,265,137	$ 55,470	$ 156,893	$ 4,485	$ 6,210,190

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : April 2008 Old

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (therms)	1,562,861	19,940	116,351	705,407	143,237	431,669	7,543	26,359	323,478	3,336,845
										5,392,449
									Sales	3,013,367
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.9801	$ 1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 1,768,221	$ 22,560	$ 122,227	$ 845,995	$ 150,470	$ 517,701	$ 7,923	$ 31,613	$ -	$ 3,466,710
Prior Period Reconciliation	$ (119,090)	$ (1,519)	$ (8,866)	$ (53,752)	$ (10,915)	$ (32,893)	$ (575)	$ (2,009)	$ -	$ (229,619)
Working Captal Allowance	$ 2,813	$ 36	$ 209	$ 1,270	$ 258	$ 777	$ 14	$ 47	$ -	$ 5,424
Supplier Refund	$ (781)	$ (10)	$ (58)	$ (353)	$ (72)	$ (216)	$ (4)	$ (13)	$ -	$ (1,507)
Bad Debt Allowance	$ 7,033	$ 90	$ 524	$ 3,174	$ 645	$ 1,943	$ 34	$ 119	$ -	$ 13,560
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,782	$ 1,782
Total Peak COG Revenues	**$ 1,658,195**	**$ 21,157**	**$ 114,036**	**$ 796,334**	**$ 140,386**	**$ 487,311**	**$ 7,392**	**$ 29,757**	**$ 1,782**	**$ 3,256,351**
Check (Total Billed Sales Rate * Therms)	$ 1,658,195	$ 21,157	$ 114,036	$ 796,334	$ 140,386	$ 487,311	$ 7,392	$ 29,757	$ 1,782	$ 3,256,351

GAS COST RECOVERY FOR THE MONTH OF : April 2008 New

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	395,235	7,754	54,531	246,473	130,163	313,038	24,621	66,585	289,329	1,527,728
										1,527,728
									Sales	1,238,399
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.3436	$1.3436	$1.2465	$1.4115	$1.2465	$1.4115	$1.2465	$1.4115	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.2732	$1.2732	$1.1761	$1.3411	$1.1761	$1.3411	$1.1761	$1.3411	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 531,038	$ 10,418	$ 67,972	$ 347,896	$ 162,248	$ 441,853	$ 30,689	$ 93,984	$ -	$ 1,686,100
Prior Period Reconciliation	$ (30,117)	$ (591)	$ (4,155)	$ (18,781)	$ (9,918)	$ (23,854)	$ (1,876)	$ (5,074)	$ -	$ (94,366)
Working Captal Allowance	$ 711	$ 14	$ 98	$ 444	$ 234	$ 563	$ 44	$ 120	$ -	$ 2,229
Supplier Refund	$ (198)	$ (4)	$ (27)	$ (123)	$ (65)	$ (157)	$ (12)	$ (33)	$ -	$ (619)
Bad Debt Allowance	$ 1,779	$ 35	$ 245	$ 1,109	$ 586	$ 1,409	$ 111	$ 300	$ -	$ 5,573
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,594	$ 1,594
Total Peak COG Revenues	$ 503,213	$ 9,872	$ 64,133	$ 330,544	$ 153,085	$ 419,815	$ 28,956	$ 89,297	$ 1,594	$ 1,600,511
Check (Total Billed Sales Rate * Therms)	$ 503,213	$ 9,872	$ 64,133	$ 330,544	$ 153,085	$ 419,815	$ 28,956	$ 89,297	$ 1,594	$ 1,600,511

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF :

May 2008 Prorated

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	773,549.6	16,572.2	91,832.9	297,533.4	113,180.5	222,478.5	7,604.6	11,936.4	178,971.9	1,713,660
										3,309,271
									Sales	1,534,688
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.3436	$1.3436	$1.2465	$1.4115	$1.2465	$1.4115	$1.2465	$1.4115	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.2732	$1.2732	$1.1761	$1.3411	$1.1761	$1.3411	$1.1761	$1.3411	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 1,039,341	$ 22,266	$ 114,470	$ 419,968	$ 141,079	$ 314,028	$ 9,479	$ 16,848	$ -	$ 2,077,481
Prior Period Reconciliation	$ (58,944)	$ (1,263)	$ (6,998)	$ (22,672)	$ (8,624)	$ (16,953)	$ (579)	$ (910)	$ -	$ (116,943)
Working Captal Allowance	$ 1,392	$ 30	$ 165	$ 536	$ 204	$ 400	$ 14	$ 21	$ -	$ 2,762
Supplier Refund	$ (387)	$ (8)	$ (46)	$ (149)	$ (57)	$ (111)	$ (4)	$ (6)	$ -	$ (767)
Bad Debt Allowance	$ 3,481	$ 75	$ 413	$ 1,339	$ 509	$ 1,001	$ 34	$ 54	$ -	$ 6,906
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 986	$ 986
Total Peak COG Revenues	$ 984,883	$ 21,100	$ 108,005	$ 399,022	$ 133,112	$ 298,366	$ 8,944	$ 16,008	$ 986	$ 1,970,425
Check (Total Billed Sales Rate * Therms)	$ 984,883	$ 21,100	$ 108,005	$ 399,022	$ 133,112	$ 298,366	$ 8,944	$ 16,008	$ 986	$ 1,970,425

155

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2008 - October 2008

GAS COST RECOVERY FOR THE MONTH OF : May-08 Prorated

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	230,187	6,657	46,481	120,636	111,[illegible]	164,206	37,361	40,854	179,803	938,156
									Sales Volumes	758,353
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 1.1382	$ 1.1382	$ 1.1210	$ 1.1889	$ 1.1210	$ 1.1889	$ 1.1210	$ 1.1889	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.00550	
Total Billed Rate	$ 1.1315	$ 1.1315	$ 1.1143	$ 1.1822	$ 1.1143	$ 1.1822	$ 1.1143	$ 1.1822	$ 0.00550	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 261,999	$ 7,577	$ 52,105.31	$ 143,423.66	$ 125,520	$ 195,224	$ 41,882	$ 48,571	$ -	$ 876,302
Prior Period Reconciliation	$ (1,565)	$ (45)	$ (316)	$ (820)	$ (761)	$ (1,117)	$ (254)	$ (278)	$ -	$ (5,157)
Working Captal Allowance	$ 368	$ 11	$ 74	$ 193	$ 179	$ 263	$ 60	$ 65	$ -	$ 1,213
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 852	$ 25	$ 172	$ 446	$ 414	$ 608	$ 138	$ 151	$ -	$ 2,806
Capacity Reserve Charge	$ (1,197)	$ (35)	$ (242)	$ (627)	$ (582)	$ (854)	$ (194)	$ (212)	$ 989	$ (2,955)
Total Off Peak COG Revenues	$ 260,457	$ 7,532	$ 51,794	$ 142,615	$ 124,770	$ 194,124	$ 41,632	$ 48,297	$ 989	$ 872,210
Check (Total Billed Sales Rate * Therms)	$ 260,457	$ 7,532	$ 51,794	$ 142,615	$ 124,770	$ 194,124	$ 41,632	$ 48,297	$ 989	$ 872,210

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2008 - October 2008

GAS COST RECOVERY FOR THE MONTH OF :

June 2008 Old

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	427,509	15,494	92,579	127,779	108,6[illegible]	126,091	7,493	5,149	1,187,536	2,098,505
									Sales Volumes	910,969
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 1.1382	$ 1.1382	$ 1.1210	$ 1.1889	$ 1.1210	$ 1.1889	$ 1.1210	$ 1.1889	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.00550	
Total Billed Rate	$ 1.1315	$ 1.1315	$ 1.1143	$ 1.1822	$ 1.1143	$ 1.1822	$ 1.1143	$ 1.1822	$ 0.00550	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 486,591	$ 17,636	$ 103,780.61	$ 151,915.98	$ 122,049	$ 149,910	$ 8,400	$ 6,122	$ -	$ 1,046,404
Prior Period Reconciliation	$ (2,907)	$ (105)	$ (629.53)	$ (868.89)	$ (740)	$ (857)	$ (51)	$ (35)	$ -	$ (6,195)
Working Captal Allowance	$ 684	$ 25	$ 148.13	$ 204.45	$ 174	$ 202	$ 12	$ 8	$ -	$ 1,458
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 1,582	$ 57	$ 342.54	$ 472.78	$ 403	$ 467	$ 28	$ 19	$ -	$ 3,371
Capacity Reserve Charge	$ (2,223)	$ (81)	$ (481.41)	$ (664.45)	$ (566)	$ (656)	$ (39)	$ (27)	$ 6,531	$ 1,794
Total Off Peak COG Revenues	$ 483,726	$ 17,532	$ 103,160	$ 151,060	$ 121,320	$ 149,065	$ 8,350	$ 6,087	$ 6,531	$ 1,046,832
Check (Total Billed Sales Rate * Therms)	$ 483,726	$ 17,532	$ 103,160	$ 151,060	$ 121,320	$ 149,065	$ 8,350	$ 6,087	$ 6,531	$ 1,046,832

June 2008 New

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	113,208	5,919	44,062	46,667	90,791	170,288	39,218	18,359	100,189	628,701
									Sales Volumes	528,512
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 1.3298	$ 1.3298	$ 1.3126	$ 1.3805	$ 1.3126	$ 1.3805	$ 1.3126	$ 1.3805	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.00550	
Total Billed Rate	$ 1.3231	$ 1.3231	$ 1.3059	$ 1.3738	$ 1.3059	$ 1.3738	$ 1.3059	$ 1.3738	$ 0.00550	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 150,544	$ 7,871	$ 57,836.31	$ 64,424.35	$ 119,172	$ 235,083	$ 51,477	$ 25,344	$ -	$ 711,751
Prior Period Reconciliation	$ (770)	$ (40)	$ (299.62)	$ (317.34)	$ (617)	$ (1,158)	$ (267)	$ (125)	$ -	$ (3,594)
Working Captal Allowance	$ 181	$ 9	$ 70.50	$ 74.67	$ 145	$ 272	$ 63	$ 29	$ -	$ 846
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 419	$ 22	$ 163.03	$ 172.67	$ 336	$ 630	$ 145	$ 68	$ -	$ 1,955
Capacity Reserve Charge	$ (589)	$ (31)	$ (229.12)	$ (242.67)	$ (472)	$ (885)	$ (204)	$ (95)	$ 551	$ (2,197)
Total Off Peak COG Revenues	$ 149,786	$ 7,831	$ 57,541	$ 64,112	$ 118,563	$ 233,942	$ 51,215	$ 25,221	$ 551	$ 708,761
Check (Total Billed Sales Rate * Therms)	$ 149,786	$ 7,831	$ 57,541	$ 64,112	$ 118,563	$ 233,942	$ 51,215	$ 25,221	$ 551	$ 708,761

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2008 - October 2008

GAS COST RECOVERY FOR THE MONTH OF :

July 2008

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	356,257	18,625	135,568	94,769	204,29[illegible]	143,498	30,816	19,511	846,683	1,850,022
									Sales Volumes	1,003,339
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 1.3298	$ 1.3298	$ 1.3126	$ 1.3805	$ 1.3126	$ 1.3805	$ 1.3126	$ 1.3805	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.00550	
Total Billed Rate	$ 1.3231	$ 1.3231	$ 1.3059	$ 1.3738	$ 1.3059	$ 1.3738	$ 1.3059	$ 1.3738	$ 0.00550	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 473,751	$ 24,768	$ 177,946.56	$ 130,828.60	$ 268,158	$ 198,099	$ 40,449	$ 26,935	$ -	$ 1,340,934
Prior Period Reconciliation	$ (2,423)	$ (127)	$ (921.86)	$ (644.43)	$ (1,389)	$ (976)	$ (210)	$ (133)	$ -	$ (6,823)
Working Captal Allowance	$ 570	$ 30	$ 216.91	$ 151.63	$ 327	$ 230	$ 49	$ 31	$ -	$ 1,605
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 1,318	$ 69	$ 501.60	$ 350.65	$ 756	$ 531	$ 114	$ 72	$ -	$ 3,712
Capacity Reserve Charge	$ (1,853)	$ (97)	$ (704.95)	$ (492.80)	$ (1,062)	$ (746)	$ (160)	$ (101)	$ 4,657	$ (561)
Total Off Peak COG Revenues	$ 471,364	$ 24,643	$ 177,038	$ 130,194	$ 266,789	$ 197,138	$ 40,243	$ 26,804	$ 4,657	$ 1,338,868
Check (Total Billed Sales Rate * Therms)	$ 471,364	$ 24,643	$ 177,038	$ 130,194	$ 266,789	$ 197,138	$ 40,243	$ 26,804	$ 4,657	$ 1,338,868

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2008 - October 2008

GAS COST RECOVERY FOR THE MONTH OF : **August 2008** old

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	215,351	12,180	92,822	47,426	88,574	52,499	6,033	3,371	732,489	1,250,744
									Sales Volumes	518,255
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 1.3298	$ 1.3298	$ 1.3126	$ 1.3805	$ 1.3126	$ 1.3805	$ 1.3126	$ 1.3805	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.00550	
Total Billed Rate	$ 1.3231	$ 1.3231	$ 1.3059	$ 1.3738	$ 1.3059	$ 1.3738	$ 1.3059	$ 1.3738	$ 0.00550	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 286,373	$ 16,197	$ 121,837.89	$ 65,471.87	$ 116,262	$ 72,475	$ 7,919	$ 4,653	$ -	$ 691,189
Prior Period Reconciliation	$ (1,464)	$ (83)	$ (631.19)	$ (322.50)	$ (602)	$ (357)	$ (41)	$ (23)	$ -	$ (3,524)
Working Captal Allowance	$ 345	$ 19	$ 148.51	$ 75.88	$ 142	$ 84	$ 10	$ 5	$ -	$ 829
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 797	$ 45	$ 343.44	$ 175.48	$ 328	$ 194	$ 22	$ 12	$ -	$ 1,918
Capacity Reserve Charge	$ (1,120)	$ (63)	$ (482.67)	$ (246.62)	$ (461)	$ (273)	$ (31)	$ (18)	$ 4,029	$ 1,334
Total Off Peak COG Revenues	$ 284,930	$ 16,115	$ 121,216	$ 65,154	$ 115,669	$ 72,123	$ 7,879	$ 4,631	$ 4,029	$ 691,745
Check (Total Billed Sales Rate * Therms)	$ 284,930	$ 16,115	$ 121,216	$ 65,154	$ 115,669	$ 72,123	$ 7,879	$ 4,631	$ 4,029	$ 691,745

August 2008 new

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	96,012	5,160	45,640	31,988	91,287	65,290	51,713	11,771	84,269	483,131
									Sales Volumes	398,862
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 1.2117	$ 1.2117	$ 1.1945	$ 1.2624	$ 1.1945	$ 1.2624	$ 1.1945	$ 1.2624	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.00550	
Total Billed Rate	$ 1.2050	$ 1.2050	$ 1.1878	$ 1.2557	$ 1.1878	$ 1.2557	$ 1.1878	$ 1.2557	$ 0.00550	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 116,338	$ 6,253	$ 54,517.22	$ 40,381.40	$ 109,042	$ 82,422	$ 61,771	$ 14,860	$ -	$ 485,585
Prior Period Reconciliation	$ (653)	$ (35)	$ (310.35)	$ (217.52)	$ (621)	$ (444)	$ (352)	$ (80)	$ -	$ (2,712)
Working Captal Allowance	$ 154	$ 8	$ 73.02	$ 51.18	$ 146	$ 104	$ 83	$ 19	$ -	$ 638
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 355	$ 19	$ 168.87	$ 118.35	$ 338	$ 242	$ 191	$ 44	$ -	$ 1,476
Capacity Reserve Charge	$ (499)	$ (27)	$ (237.33)	$ (166.34)	$ (475)	$ (340)	$ (269)	$ (61)	$ 463	$ (1,611)
Total Off Peak COG Revenues	$ 115,695	$ 6,218	$ 54,211	$ 40,167	$ 108,431	$ 81,985	$ 61,424	$ 14,781	$ 463	$ 483,376
Check (Total Billed Sales Rate * Therms)	$ 115,695	$ 6,218	$ 54,211	$ 40,167	$ 108,431	$ 81,985	$ 61,424	$ 14,781	$ 463	$ 483,376

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2008 - October 2008

GAS COST RECOVERY FOR THE MONTH OF :

September 2008 old

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	228,167	12,715	95,970	51,375	98,[illegible]	65,940	6,348	5,859	742,976	1,307,625
									Sales Volumes	564,649
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 1.2117	$ 1.2117	$ 1.1945	$ 1.2624	$ 1.1945	$ 1.2624	$ 1.1945	$ 1.2624	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.00550	
Total Billed Rate	$ 1.2050	$ 1.2050	$ 1.1878	$ 1.2557	$ 1.1878	$ 1.2557	$ 1.1878	$ 1.2557	$ 0.00550	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 276,470	$ 15,407	$ 114,635.69	$ 64,856.18	$ 117,388	$ 83,243	$ 7,583	$ 7,396	$ -	$ 686,979
Prior Period Reconciliation	$ (1,552)	$ (86)	$ (652.59)	$ (349.35)	$ (668)	$ (448)	$ (43)	$ (40)	$ -	$ (3,840)
Working Captal Allowance	$ 365	$ 20	$ 153.55	$ 82.20	$ 157	$ 106	$ 10	$ 9	$ -	$ 903
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 844	$ 47	$ 355.09	$ 190.09	$ 364	$ 244	$ 23	$ 22	$ -	$ 2,089
Capacity Reserve Charge	$ (1,186)	$ (66)	$ (499.04)	$ (267.15)	$ (511)	$ (343)	$ (33)	$ (30)	$ 4,086	$ 1,150
Total Off Peak COG Revenues	$ 274,942	$ 15,322	$ 113,993	$ 64,512	$ 116,730	$ 82,801	$ 7,541	$ 7,357	$ 4,086	$ 687,283
Check (Total Billed Sales Rate * Therms)	$ 274,942	$ 15,322	$ 113,993	$ 64,512	$ 116,730	$ 82,801	$ 7,541	$ 7,357	$ 4,086	$ 687,283

September 2008 new

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	102,560	5,082	42,553	33,774	100,014	84,390	25,018	22,991	98,330	514,711
									Sales Volumes	416,381
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 0.9372	$ 0.9372	$ 0.9200	$ 0.9879	$ 0.9200	$ 0.9879	$ 0.9200	$ 0.9879	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.0055	
Total Billed Rate	$ 0.9305	$ 0.9305	$ 0.9133	$ 0.9812	$ 0.9133	$ 0.9812	$ 0.9133	$ 0.9812	$ 0.0055	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 96,119	$ 4,763	$ 39,149.13	$ 33,365.04	$ 92,013	$ 83,369	$ 23,016	$ 22,713	$ -	$ 394,507
Prior Period Reconciliation	$ (697)	$ (35)	$ (289.36)	$ (229.66)	$ (680)	$ (574)	$ (170)	$ (156)	$ -	$ (2,831)
Working Captal Allowance	$ 164	$ 8	$ 68.09	$ 54.04	$ 160	$ 135	$ 40	$ 37	$ -	$ 666
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 379	$ 19	$ 157.45	$ 124.96	$ 370	$ 312	$ 93	$ 85	$ -	$ 1,541
Capacity Reserve Charge	$ (533)	$ (26)	$ (221.28)	$ (175.62)	$ (520)	$ (439)	$ (130)	$ (120)	$ 541	$ (1,624)
Total Off Peak COG Revenues	$ 95,432	$ 4,729	$ 38,864	$ 33,139	$ 91,343	$ 82,804	$ 22,849	$ 22,559	$ 541	$ 392,258
Check (Total Billed Sales Rate * Therms)	$ 95,432	$ 4,729	$ 38,864	$ 33,139	$ 91,343	$ 82,804	$ 22,849	$ 22,559	$ 541	$ 392,258

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2008 - October 2008

GAS COST RECOVERY FOR THE MONTH OF :

October 2008

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	453,744	18,612	118,574	144,887	193,834	244,219	45,956	37,166	1,418,199	2,675,191
									Sales Volumes	1,256,992
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 0.9372	$ 0.9372	$ 0.9200	$ 0.9879	$ 0.9200	$ 0.9879	$ 0.9200	$ 0.9879	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.0055	
Total Billed Rate	$ 0.9305	$ 0.9305	$ 0.9133	$ 0.9812	$ 0.9133	$ 0.9812	$ 0.9133	$ 0.9812	$ 0.0055	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 425,249	$ 17,443	$ 109,088.08	$ 143,133.87	$ 178,327	$ 241,264	$ 42,280	$ 36,716	$ -	$ 1,193,501
Prior Period Reconciliation	$ (3,085)	$ (127)	$ (806.30)	$ (985.23)	$ (1,318)	$ (1,661)	$ (313)	$ (253)	$ -	$ (8,548)
Working Captal Allowance	$ 726	$ 30	$ 189.72	$ 231.82	$ 310	$ 391	$ 74	$ 59	$ -	$ 2,011
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 1,679	$ 69	$ 438.72	$ 536.08	$ 717	$ 904	$ 170	$ 138	$ -	$ 4,651
Capacity Reserve Charge	$ (2,359)	$ (97)	$ (616.58)	$ (753.41)	$ (1,008)	$ (1,270)	$ (239)	$ (193)	$ 7,800	$ 1,264
Total Off Peak COG Revenues	$ 422,209	$ 17,318	$ 108,294	$ 142,163	$ 177,029	$ 239,628	$ 41,972	$ 36,467	$ 7,800	$ 1,192,879
Check (Total Billed Sales Rate * Therms)	$ 422,209	$ 17,318	$ 108,294	$ 142,163	$ 177,029	$ 239,628	$ 41,972	$ 36,467	$ 7,800	$ 1,192,879

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2008 - October 2008

GAS COST RECOVERY FOR THE MONTH OF : Nov-08 Prorated

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	761,549	18,707	89,575	289,537	130,92[illegible]	269,651	12,128	19,532	1,820,285	3,411,890
									Sales Volumes	1,591,605
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$ 0.9372	$ 0.9372	$ 0.9200	$ 0.9879	$ 0.9200	$ 0.9879	$ 0.9200	$ 0.9879	$ -	
Prior Period Reconciliation	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ (0.0068)	$ -	
Working Captal Allowance	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ -	
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Allowance	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ 0.0037	$ -	
Capacity Reserve Charge	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ (0.0052)	$ 0.0055	
Total Billed Rate	$ 0.9305	$ 0.9305	$ 0.9133	$ 0.9812	$ 0.9133	$ 0.9812	$ 0.9133	$ 0.9812	$ 0.0055	
Off Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 713,724	$ 17,532	$ 82,409	$ 286,033	$ 120,452	$ 266,389	$ 11,157	$ 19,296	$ -	$ 1,516,992
Prior Period Reconciliation	$ (5,179)	$ (127)	$ (609)	$ (1,969)	$ (890)	$ (1,834)	$ (82)	$ (133)	$ -	$ (10,823)
Working Captal Allowance	$ 1,218	$ 30	$ 143	$ 463	$ 209	$ 431	$ 19	$ 31	$ -	$ 2,547
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 2,818	$ 69	$ 331	$ 1,071	$ 484	$ 998	$ 45	$ 72	$ -	$ 5,889
Capacity Reserve Charge	$ (3,960)	$ (97)	$ (466)	$ (1,506)	$ (681)	$ (1,402)	$ (63)	$ (102)	$ 10,012	$ 1,735
Total Off Peak COG Revenues	$ 708,621	$ 17,407	$ 81,809	$ 284,093	$ 119,575	$ 264,582	$ 11,076	$ 19,165	$ 10,012	$ 1,516,340
Check (Total Billed Sales Rate * Therms)	$ 708,621	$ 17,407	$ 81,809	$ 284,093	$ 119,575	$ 264,582	$ 11,076	$ 19,165	$ 10,012	$ 1,516,340

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2008 - April 2009

FORM III
Schedule 3
Page 2 of 8

GAS COST RECOVERY FOR THE MONTH OF : November 2008 **Prorated**

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	284,158	6,593	36,991	142,042	111,511	272,986	28,294	54,747	214,572	1,151,894
										1,151,894
									Sales	937,322
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.2776	$1.2776	$1.0748	$1.4089	$1.0748	$1.4089	$1.0748	$1.4089	$ -	
Prior Period Reconciliation	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	$ -	
Working Captal Allowance	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$ -	
Supplier Refund	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ -	
Bad Debt Allowance	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$ -	
Capacity Reserve Charge	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	$ 0.0055	
Total Billed Rate	$1.2636	$1.2636	$1.0608	$1.3949	$1.0608	$1.3949	$1.0608	$1.3949	$ 0.0055	
Peak Period Demand/Commodity Recovery Revenues										
Demand & Commodity	$ 363,040	$ 8,423	$ 39,758	$ 200,124	$ 119,852	$ 384,610	$ 30,410	$ 77,133	$ -	$ 1,223,350
Prior Period Reconciliation	$ (5,541)	$ (129)	$ (721)	$ (2,770)	$ (2,174)	$ (5,323)	$ (552)	$ (1,068)	$ -	$ (18,278)
Working Captal Allowance	$ 625	$ 15	$ 81	$ 312	$ 245	$ 601	$ 62	$ 120	$ -	$ 2,062
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 1,478	$ 34	$ 192	$ 739	$ 580	$ 1,420	$ 147	$ 285	$ -	$ 4,874
Capacity Reserve Charge	$ (540)	$ (13)	$ (70)	$ (270)	$ (212)	$ (519)	$ (54)	$ (104)	$ 1,180	$ (601)
Total Peak COG Revenues	**$ 359,062**	**$ 8,331**	**$ 39,240**	**$ 198,135**	**$ 118,291**	**$ 380,788**	**$ 30,014**	**$ 76,366**	**$ 1,180**	**$ 1,211,407**
Check (Total Billed Sales Rate * Therms)	$ 359,062	$ 8,331	$ 39,240	$ 198,135	$ 118,291	$ 380,788	$ 30,014	$ 76,366	$ 1,180	$ 1,211,407

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2008 - April 2009

GAS COST RECOVERY FOR THE MONTH OF : December 2008

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	1,949,850	32,526	156,247	1,047,211	311,152	1,045,146	44,411	143,436	3,475,106	8,205,085
										0
									Sales	4,729,979
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.2776	$1.2776	$1.0748	$1.4089	$1.0748	$1.4089	$1.0748	$1.4089	$ -	
Prior Period Reconciliation	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	($0.0195)	$ -	
Working Captal Allowance	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022	$ -	
Supplier Refund	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ -	
Bad Debt Allowance	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$ -	
Capacity Reserve Charge	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	($0.0019)	$ 0.0055	
Total Billed Rate	$1.2636	$1.2636	$1.0608	$1.3949	$1.0608	$1.3949	$1.0608	$1.3949	$ 0.0055	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 2,491,128	$ 41,555	$ 167,934	$ 1,475,416	$ 334,426	$ 1,472,506	$ 47,733	$ 202,087	$ -	$ 6,232,786
Prior Period Reconciliation	$ (38,022)	$ (634)	$ (3,047)	$ (20,421)	$ (6,067)	$ (20,380)	$ (866)	$ (2,797)	$ -	$ (92,235)
Working Captal Allowance	$ 4,290	$ 72	$ 344	$ 2,304	$ 685	$ 2,299	$ 98	$ 316	$ -	$ 10,406
Supplier Refund	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Allowance	$ 10,139	$ 169	$ 812	$ 5,445	$ 1,618	$ 5,435	$ 231	$ 746	$ -	$ 24,596
Capacity Reserve Charge	$ (3,705)	$ (62)	$ (297)	$ (1,990)	$ (591)	$ (1,986)	$ (84)	$ (273)	$ 19,113	$ 10,126
Total Peak COG Revenues	**$ 2,463,830**	**$ 41,100**	**$ 165,747**	**$ 1,460,755**	**$ 330,070**	**$ 1,457,874**	**$ 47,111**	**$ 200,079**	**$ 19,113**	**$ 6,185,679**
Check (Total Billed Sales Rate * Therms)	2,463,830	41,100	165,747	1,460,755	330,070	1,457,874	47,111	200,079	19,113	6,185,679

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(21) A description of the utility's projected need for external capital for the 2 year period immediately following the test year.

Response:

Northern reviews and analyzes its long-term financing requirements in light of its long-term objective to maintain investment grade capitalization ratios. Principally due to the size of Northern's capital expenditures, Northern has a financing cycle that requires it to seek external long-term capital periodically, approximately every two to three years. This time frame gives Northern flexibility in determining the market timing of its financings and allows for sufficient "build up" of short-term debt levels and corresponding plant investment prior to going to the market for long-term financing.

Over the next two years, Northern will likely be in a position to seek long-term financing and may request authority to issue long-term debt securities. However, at this time, Northern does not have any definitive plans in place. Northern will continue to monitor its needs for long-term external capital and will inform the Commission if it finalizes a financing plan.

For short-term debt financing, Northern participates in Unitil Corporation's Cash Pooling and Loan Agreement to fund construction expenditures and working capital requirements up to the Commission's currently authorized limit of $46 million which is subject to annual adjustment.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(22) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately subsequent to the test year.

Response:

Please see PUC 1604.01. (a) 22 - Attachment 1 - Confidential for the projected sources and uses of funds for calendar years 2011 and 2012.

Northern Utilities, Inc. - New Hampshire
Sources and Uses of Funds for Years 2011 and 2012
Including the Projected Construction Budgets
($000)

See Volume 4 of 4 for Puc 1604.01(a) 22 - Attachment1 CONFIDENTIAL

Notes:
* 2011 Budget and 2012 Forecast include rate relief.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(23) The provisions of any sinking funds associated with senior capital and a description of the rate at which any respective issues of senior capital will be retired, consistent with such sinking fund(s).

Response:

Please see the attached schedule of NU Sinking Fund Commitments, which commence in 2016.

Northern Utilities, Inc.
Sinking Fund Commitments

PUC 1604.01(a) (23)
Attachment 1
Page 1 of 1

	$ 30,000,000	$ 50,000,000	$ 25,000,000	
	10 years	30 years	10 years	
	Series A	Series B		
	6.95%	7.72%	5.29%	
	Due 12/3/2018	Due 12/3/2038	Due 3/2/2020	NU
	SF beg 12/3/2016	SF beg 12/3/2029	SF beg 3/2/2018	Total
2010				-
2011				-
2012				-
2013				-
2014				-
2015				-
2016	$10,000,000			$10,000,000
2017	10,000,000			10,000,000
2018	10,000,000		$8,400,000	18,400,000
2019			8,400,000	8,400,000
2020			8,200,000	8,200,000
2021				-
2022				-
2023				-
2024				-
2025				-
2026				-
2027				-
2028				-
2029		$5,000,000		5,000,000
2030		5,000,000		5,000,000
2031		5,000,000		5,000,000
2032		5,000,000		5,000,000
2033		5,000,000		5,000,000
2034		5,000,000		5,000,000
2035		5,000,000		5,000,000
2036		5,000,000		5,000,000
2037		5,000,000		5,000,000
2038		5,000,000		5,000,000
2039				-
2040				-
	$30,000,000	$50,000,000	$25,000,000	$105,000,000

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(24) If the short-term debt component of total invested capital is volatile, the amount outstanding, on a monthly basis, during the test year, for each short-term indebtedness.

Response:

NU is a member of the Unitil Corporation Cash Pool, which is the financing vehicle for day-to-day borrowing and investing. Please refer to the attached schedule, showing NU's end of month balance and average daily balance of short-term debt outstanding within the Cash Pool for each month during the test year.

Northern Utilities, Inc.
Short-Term Debt Outstanding
12 Months Ended December 31, 2010

Line No.	Month	Month-End Amount Outstanding	Average Daily Borrowings
1	January 2010	$ 45,164,198	$ 43,140,905
2	February 2010	33,788,814	32,471,741
3	March 2010	2,710,824	6,034,661
4	April 2010	-	330,366
5	May 2010	-	-
6	June 2010	2,597,225	341,489
7	July 2010	4,793,155	3,773,853
8	August 2010	11,598,374	8,112,580
9	September 2010	17,460,127	14,715,058
10	October 2010	20,759,671	18,905,144
11	November 2010	23,031,390	21,940,087
12	December 2010	29,050,170	27,158,618

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements
Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.01) The utility's internal financial reports for the following periods:

a. For the first and last month of the test year;

b. For the entire test year; and

c. For the 12 months or 5 quarters prior to the test year.

Response:

Unitil Corporation (Unitil) was incorporated under the laws of the State of New Hampshire in 1984. Unitil is a registered public utility holding company under the Public Utility Holding Act of 1935 and is the parent company of the Unitil System. Northern Utilities, Inc. is a subsidiary of Unitil.

Where applicable, information for Unitil has been provided for elsewhere in these supplemental filing requirements.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
Consolidated Balance Sheet

	December 2009	January 2010	December 2010
ASSETS			
Utility Plant, at Cost:			
Electric	302,264,273.18	304,340,249.37	321,496,661.30
Gas	325,512,493.05	323,962,000.99	360,145,137.66
Common	28,490,718.36	28,512,374.06	29,788,587.35
Const. Work in Progress	25,960,561.15	25,869,281.05	16,607,967.14
Total Utility Plant	682,228,045.74	682,683,905.47	728,038,353.45
Less: Accum. Depr & Amort	(232,519,481.70)	(233,919,960.96)	(251,507,742.36)
Net utility plant	449,708,564.04	448,763,944.51	476,530,611.09
Other Property and Investments:			
Nonutility Property, net of Amort.	1,341,502.25	1,319,563.70	1,190,891.25
Other Investments at Cost	2,203.41	2,203.41	2,203.41
Total Other Prop. & Invest.	1,343,705.66	1,321,767.11	1,193,094.66
Current Assets:			
Cash	305,915.15	1,491,651.44	354,175.58
Other Special Deposits	7,424,889.93	7,299,264.82	8,583,722.28
Accounts Receivable-net of:			
Allow. for doubtful accts	33,504,349.48	50,208,969.76	36,878,233.43
Materials & Supplies	5,246,499.51	4,692,454.19	5,178,143.73
Prepayments	17,868,571.07	18,438,721.56	17,427,933.68
Accrued revenue	43,822,692.55	42,331,823.44	46,664,018.28
Misc Current Assets	12,444,531.71	10,679,767.78	9,176,667.36
Total Current Assets	120,617,449.40	135,142,652.99	124,262,894.34
Regulatory Assets:			
Regulatory Assets	130,978,418.30	117,097,272.23	122,790,401.78
Deferred Debits:			
Unamortized Debt Expense	3,442,752.42	3,321,349.30	3,853,160.87
Preliminary Survey Chgs	595,447.11	639,313.01	886,486.40
Clearing Accounts	1,871,480.49	2,330,980.68	1,385,659.26
Other Deferred Debits	30,646,553.91	38,317,230.17	35,861,551.42
Total Deferred Debits	167,534,652.23	161,706,145.39	164,777,259.73
TOTAL ASSETS	739,204,371.33	746,934,510.00	766,763,859.82

	December 2009	January 2010	December 2010
LIABILITIES AND CAPITAL			
Capitalization:			
Common Stock Equity			
Common Stock of Parent, No Par	167,894,315.59	167,923,695.78	169,171,178.07
Misc. Paid in Capital	913,081.89	948,047.47	906,972.73
Capital Stock Expense	(9,185,996.17)	(9,185,996.17)	(9,185,996.17)
Retained earnings	33,567,095.62	32,486,660.79	28,060,063.93
Total Common Equity	193,188,496.93	192,172,407.87	188,952,218.56
Preferred Stock:			
Non-Redeemable, Non-Cumulative	225,000.00	225,000.00	225,000.00
Redeemable, Cumulative	1,789,300.00	1,789,300.00	1,764,300.00
Total Preferred Stock	2,014,300.00	2,014,300.00	1,989,300.00
LT Debt-Net of Curr. Install	248,842,993.77	248,805,880.73	288,380,939.16
Total Capitalization	444,045,790.70	442,992,588.60	479,322,457.72
Current Liabilities:			
LT Debt Due Within One Year	426,643.45	429,487.74	462,054.61
Notes payable	64,485,000.00	67,755,000.00	66,805,000.00
Accounts payable	48,173,588.60	48,581,519.58	43,511,810.41
Customer deposits	3,957,068.86	3,935,942.23	3,319,690.36
Taxes accrued	(1,736,486.10)	2,096,443.93	(7,473,194.69)
Interest accrued	2,345,716.79	3,369,150.11	3,167,226.39
Dividends Declared - Preferred	33,337.69	41,075.25	32,982.16
Dividends Declared - Common		3,739,192.11	(0.00)
Misc current liabilities	9,689,821.56	8,969,312.88	8,858,147.00
Capital Leases - Current	655,874.66	651,990.51	779,771.40
Total current liabilities	128,030,565.51	139,569,114.34	119,463,487.64
Deferred Credits:			
Cust Adv for Construction	1,225,225.11	1,222,119.71	1,420,734.89
Unamort. Invest. Tax Credit	102,837.19	100,690.19	77,073.19
Other Deferred Credits	128,304,050.69	127,680,010.33	124,760,163.70
Total Deferred Credits	129,632,112.99	129,002,820.23	126,257,971.78
Deferred Income Tax	36,619,300.17	34,539,447.31	40,999,832.26
Capital Leases-Noncurrent	876,601.96	830,539.52	720,110.42
TOTAL LIABILITIES AND CAPITAL	739,204,371.33	746,934,510.00	766,763,859.82

	YTD December 2009	MTD January 2010	MTD December 2010	YTD December 2010
Operating Revenues:				
Electric	$209,333,847.84	$18,459,776.23	$17,244,283.53	$205,331,417.48
Other Electric	535,473.49	(557,906.70)	1,131,454.55	(1,587,581.27)
Gas	157,588,286.95	32,905,253.39	24,957,884.67	148,165,779.59
Other Gas	(4,784,479.86)	(7,317,200.34)	(3,384,572.25)	1,901,107.42
Other	4,286,125.19	384,406.02	391,452.89	4,578,325.55
Total Operating Revenues	366,959,253.61	43,874,328.60	40,340,503.39	358,389,048.77
Operating Expenses:				
Purchased Electricity	151,616,169.51	13,143,053.09	10,912,735.02	137,668,536.10
Purchased Gas	96,405,403.09	16,604,386.53	12,322,427.09	90,506,307.91
Operation and Maintenance	44,715,464.46	4,284,844.42	3,737,439.73	48,779,472.88
Conservation & Load Management:				
Electric C&LM	3,151,400.94	254,631.30	1,195,382.14	5,968,078.68
Gas C&LM	1,882,837.41	294,733.04	275,546.20	2,863,606.09
Depreciation & Amortization	27,425,119.03	2,373,182.88	3,649,018.21	28,922,159.98
Provisions for Taxes:				
Business Enterprise Tax	201,996.00	19,287.00	19,287.00	231,694.00
Local Property and Other	10,209,157.55	980,443.16	919,848.99	11,197,648.16
Federal and State Income	5,220,131.79	1,862,501.00	1,333,159.17	4,232,871.61
Total Operating Expenses	340,827,679.78	39,817,062.42	34,364,843.55	330,370,375.41
Operating Income	26,131,573.83	4,057,266.18	5,975,659.84	28,018,673.36
Non-operating Expenses (Income)	254,963.86	27,655.64	28,059.46	332,464.76
Income before Interest Expense	25,876,609.97	4,029,610.54	5,947,600.38	27,686,208.60
Interest Expense, net	15,827,398.91	1,359,740.70	1,731,060.30	18,070,268.68
Net Income	10,049,211.06	2,669,869.84	4,216,540.08	9,615,939.92
Less: Pref. Dividend Req.	133,721.95	11,112.56	10,994.03	132,284.13
Net Income Appl. to Comm.	$9,915,489.11	$2,658,757.28	$4,205,546.05	$9,483,655.79

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.02) Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years.

Response:

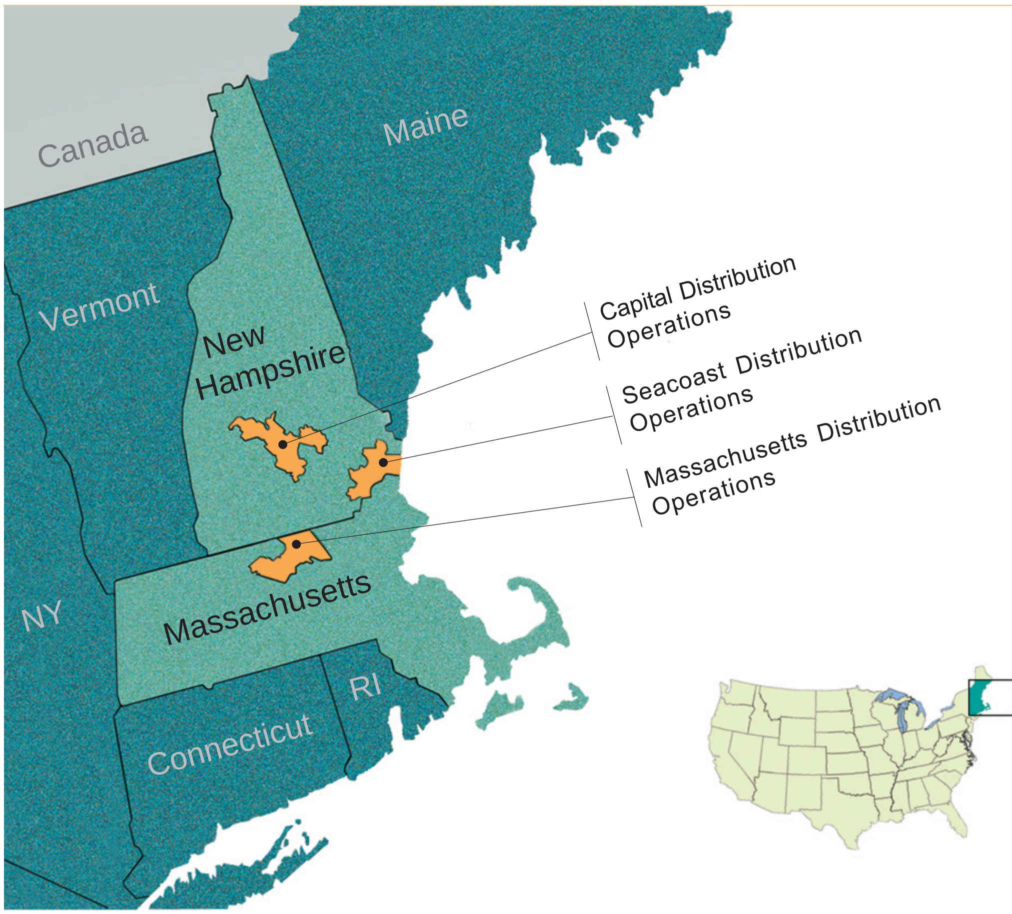
Please see the attached for copies of Unitil Corporation's annual reports to stockholders for the years 2005 through 2010.

Unitil

We deliver. It's that simple.

Annual Report 2005

Unitil Distribution Service Territories



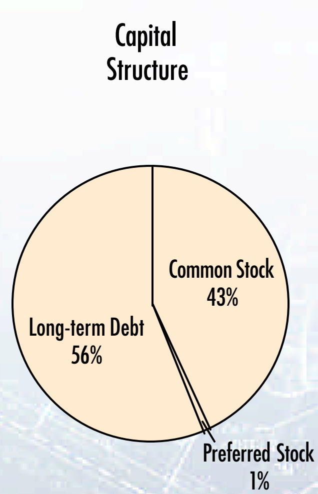
About the Company

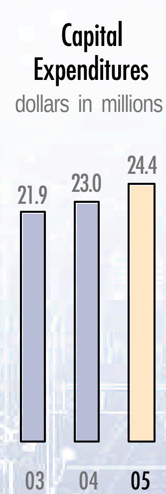
Unitil (AMEX: UTL) is a public utility holding company with regulated utility subsidiaries providing electric service in New Hampshire and electric and natural gas service in Massachusetts. The Company also provides energy brokering and consulting services through its non-utility subsidiary.

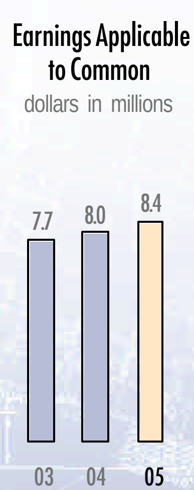
Additional information is available on line at www.unitil.com. Unitil's subsidiaries include Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Service Corp., Unitil Resources, Inc., and its non-utility unregulated business, Usource.

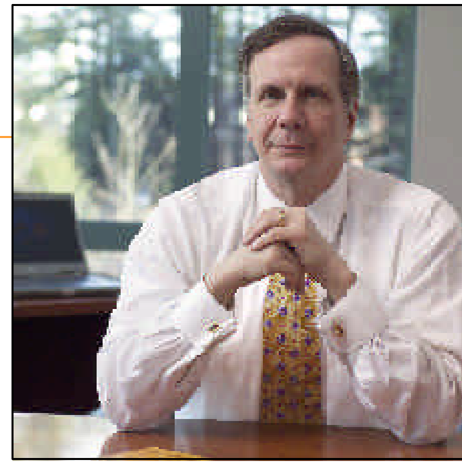
Financial Highlights

	2005	2004	2003
Financial Data (000's)			
Total Operating Revenues	**$ 232,145**	$ 214,137	$ 220,654
Total Operating Income	**$ 15,541**	$ 15,193	$ 15,449
Earnings Applicable to Common	**$ 8,397**	$ 8,011	$ 7,722
Capital Expenditures	**$ 24,367**	$ 22,922	$ 21,939
Common Share Data			
Diluted Earnings per Share	**$ 1.51**	$ 1.45	$ 1.58
Dividends Paid per Share	**$ 1.38**	$ 1.38	$ 1.38
Book Value per Share (Year-end)	**$ 17.21**	$ 17.00	$ 16.87
Market Price (Year-end)	**$ 25.16**	$ 28.30	$ 25.80
Average Common Shares Outstanding (000's)	**5,568**	5,525	4,896
Operating Data			
Electric Distribution Sales (mWh)	**1,790,405**	1,742,131	1,717,664
Firm Gas Distribution Sales (000's of Therms)	**24,332**	23,151	24,592
Customers Served (Year-end)	**113,593**	112,288	110,916









During 2005, Unitil completed its key objectives for the year and posted solid financial performance, with earnings up almost 5% over 2004.

Earnings per share increased to $1.51, while sales of electricity grew 2.8% over 2004, and sales of natural gas grew 5.1%. Capital investments in our gas and electric systems reached a new record of $24 million, an increase of 6.3% over 2004. Usource, our unregulated energy brokerage business, achieved profitability, growing revenues to $2 million, an increase of more than 30% over 2004.

These financial statistics tell a good story about Unitil in a back-to-basics industry environment. Our operating statistics also speak well of our accomplishments in 2005. Despite an unusually high number of storms, Unitil performed among the best in peer group benchmarking for electric system reliability in 2005. In addition, even in the midst of record-high energy prices, our customer satisfaction survey scores remained well above national and regional averages.

Challenges to our industry — and to our business — remain. We provide the lowest-cost energy distribution services in the region, but record-high energy prices impact all our customers, and energy supply is by far the largest single component of our customers' bills. Our energy procurement process helps assure the best supply prices possible. However, wholesale energy costs, which we do not control, are driven by global market forces, and those prices impact what matters most to customers – the bottom line total bill.

Some signs of price settling have occurred recently in domestic natural gas markets, as the industry recovers from the fall hurricanes. In time, wholesale electricity market prices are expected to follow. Oil markets continue to show instability, however, and the geopolitical stage is as uncertain as it ever was.

Turbulent energy prices can increase legislative and regulatory uncertainty. Fortunately, the two states in which we operate our distribution systems — Massachusetts and New Hampshire — have maintained their strong and consistent commitment to energy cost recovery. In New Hampshire, legislation was passed this fall to assist low-income customers with their energy bills. Regulatory support for the continued transition to competitive energy supply markets also remains intact. We strongly believe that competitive energy markets are the best long-term solution for our customers.

Two additional challenges are the rapidly changing nature of technology and the aging of the utility work force. Efficiency and productivity, undeniably the key drivers behind continued long-term economic growth, demand new techniques, new systems, new technologies, and new business processes. The aging of the utility workforce means preserving key technical and institutional knowledge and finding replacement workers with the skills to use technology to do more with less. Integrating people and technology has become a fundamental and critical business objective. It is a priority in Unitil's strategic plan for 2006.

The Intersection of Technology & People

Meter reading is a key utility function. Metering equipment must be installed on each customer account, and monthly meter readings become the starting point for the Company's revenue cycle and cash flow. Remarkably, the core technology for metering electric and gas consumption has remained essentially unchanged for nearly a century. At Unitil, that is all about to change.

In 2006, Unitil will be installing, testing, and deploying an advanced metering infrastructure that will provide automated, two-way meter reading capability for all of Unitil's customers. The system utilizes a power-line-carrier information transmission technology to collect data from metering endpoints. It gathers the data at the substation level and transmits it digitally to a central processor, which generates it in usable form. This system replaces all the trucks, hand-held data recorders, related equipment, and meter readers in our three distribution areas.

This project is the single largest capital investment, and the single largest workforce transition in the Company's history. It will generate significant cost savings, and it will significantly improve service to customers and provide an advanced technology platform capable of additional enhancements in the years ahead. Estimated meter reads, for example, will be a thing of the past.

This technology also provides an answer to a critical workforce transition issue – the pending retirement of a large number of our utility workers. By committing to retrain and redeploy displaced meter readers to positions vacated by retirements, Unitil will avoid laying off good workers and will be able to offer them advancement opportunities. It is a win/win for the Company and our employees.

Technology Changes Regulation

As a regulated utility, Unitil is required to petition its state regulators before it makes any changes in its services or prices. Traditionally, such changes have been made in the context of formal rate cases — laborious and complicated proceedings conducted every few years, as utility revenues and costs have changed through time. For a variety of reasons, these very traditions have changed.

One important reason for the change is the development of sophisticated data management and analysis tools and techniques over the past two decades. As a result, regulators are able to obtain more data and more sophisticated analyses, and to require faster compliance. Utilities are able to analyze trends and file requests more quickly, and with a far higher degree of accuracy.

Traditional regulation has relied heavily on the concepts of ebb and flow in helping to provide incentives to regulated utilities. The "ebb and flow" concept recognized that actual costs and revenues would vary through time, but presumed that such changes would tend to be offsetting and would encourage utilities to be cost conscious.

As computers and the software for data management have become more powerful and sophisticated over time, utilities and regulators have been able to improve on the rate process. They have linked rate recovery of specific cost items to actual costs, with the technique of reconciling cost recovery mechanisms, or cost trackers. Originally put in place to address rapid fluctuations in fuel costs, cost trackers have now become accepted tools for recovery of the costs of energy supply, energy transmission, environmental remediation, energy contract administration, energy efficiency, low-income discounts, and pension and post-retirement benefits. Unitil administers 31 cost mechanisms in its two jurisdictions. These mechanisms help us better meet our obligations to serve customers.

Technology Changes the Work that People Do

Building and operating a gas or electric distribution system is a complex engineering undertaking that requires sophisticated maps, tools, and analyses. A generation ago, the single most important tool for engineers was a slide rule. Today, Unitil's engineering staff relies on advanced computerized databases and analytical software that demand new skills and new approaches to the same job – designing, planning, testing, evaluating, mapping, and maintaining the Company's core assets.

One of the tools that has become relatively commonplace is CAD – computer aided design. CAD vastly simplifies the tasks of mapping, designing, and analyzing our systems and provides new and expanded capabilities in system engineering and design. The latest new development goes far beyond, however, by linking the Company's engineering and system data together with the Company's customer, operations, and accounting data, through a geographical information system, or GIS.

GIS provides the capability to integrate all of the Company's asset-related functions, from engineering, design, and mapping, through project estimation and materials ordering, field construction, and plant accounting. What was once largely a process of manual, human communication and information transfer between these functions is being digitized and automated.

The productivity and efficiency improvements enabled by the GIS technology are transformational. Analytical sophistication, data accuracy and integrity, and financial controls are significantly enhanced, and the knowledge, training, and skills of our employees are at a much higher level. We now have the ability to get an instantaneous real-time picture of our distribution systems.

GIS benefits Unitil's employees by helping them work better and faster — giving them new skills and advanced tools to serve our customers. Unitil's customers benefit by improved systems and services and increased cost-effectiveness.

Technology Changes Our Relationships with Our Customers

Every month, Unitil issues approximately 114,000 bills and collects, on average, more than $20 million in revenues. In any given month, we may get 20,000 phone calls from customers for a wide variety of reasons, including account inquiries, requests to initiate or terminate an account, outage reports, or requests for information or assistance. The basic nature of these interactions has been the same for many decades.

Increasingly, technology is introducing new modes for conducting business and communicating with customers. Company/customer relationships are being transformed; the new world puts information, choices, and control in the hands of the consumer.

Two years ago Unitil installed an Integrated Voice Response (IVR) system, along with web-enabled customer service functions, that allowed customers to conduct and manage transactions with the Company without direct contact with a Company employee. This new functionality provides tools for customers to review and to pay their bills on-line or over the phone. They can report power outages through the IVR, and the phone system is able to handle vastly increased call volumes – a critical function during major outages, when time of response is of the essence. Customers can also initiate or terminate accounts and set up payment arrangements quickly, conveniently, and directly.

From the customer standpoint, these added functions and services are valuable features. From the Company standpoint, the new technology and systems are significant cost reducers.

As banks have found, over-the-counter transactions involving face-to-face contact are the most expensive. Billing and payment by mail and check is much more economical, but electronic transactions with no direct employee intervention or handling are by far the most cost-effective. Moreover, the IVR reduces the number of calls that Customer Service representatives have to answer. The average call handled in person may be more complex, but overall, the IVR reduces call time and, ultimately, reduces the staffing required to answer customer calls quickly and efficiently. At the same time, our customers can always speak with a real person in Customer Service, 24 hours a day, seven days a week.

This year Unitil is adding Voice Over Internet Protocol (VOIP) capability to its phone system. While transparent to customers, the technology will improve service and reduce costs by allowing digital bandwidth to carry both voice and data. Moreover, when combined with technology that provides secure remote access over broadband, it will enable employees to "plug in" and perform a full range of operations and functions from any location. Reduced costs – added flexibility and convenience – improved services to customers: Technology is transforming customer relationships.

All of these technological innovations will enable Unitil to work faster, cheaper, and better for our customers. We are continuing to accomplish all this with fewer workers than we had five years ago.

Unitil's senior management team (l. to r.): Raymond Morrissey, Vice President Information Systems; Todd Black, Vice President Usource; Tom Meissner, Senior Vice President & Chief Operating Officer; Larry Brock, Controller & Chief Accounting Officer; Bob Schoenberger, Chairman of the Board of Directors, President, & Chief Executive Officer; George Gantz, Senior Vice President Customer Services & Communications; Mark Collin, Senior Vice President, Chief Financial Officer & Treasurer; George Long, Vice President Administration.

Building our Strategies from the Bottom Up

These are only a sample of the ways in which our business is being transformed by technology and changing workforce issues. We recognize the increasing importance of this transformation to our business, and have added a new strategy to our 2006 Strategic Plan – Operations Transformation. The strategy recognizes that the Company is evolving rapidly in response to both external drivers and internal redesign and innovation. Our goal, consistent with our operational and financial objectives, is to be the most advanced and technologically capable distribution utility in the region.

We will continue to pursue our other four strategies aggressively: Regulation of Utility Business, Gas Distribution Growth, Electric Distribution Growth, and Usource.

The regulatory strategy will focus on the completion of a traditional distribution rate case for our New Hampshire subsidiary in 2006, the continued procurement of cost-effective wholesale energy supplies for our customers, and the exploration of performance-based rate-making options for our Massachusetts subsidiary.

In late 2004, we began a new initiative to grow our natural gas business. In 2005, we achieved our overall goals for growth in sales and net income, and posted a 5.1% increase in sales of firm natural gas distribution service. Despite the twin challenges of higher energy prices and economic uncertainty, we can turn what had been a static business into a growing one.

Our electric distribution business spans three diverse service territories in New Hampshire and Massachusetts. Residential growth has remained strong in our New Hampshire service areas and has been accelerating in north central Massachusetts. In the last year, we have seen signs of a catch-up in retail and commercial growth, and industrial sales have stabilized. Overall kilowatt-hour sales were up 2.8% for the year.

Usource continues to grow. By following a balanced strategy focused on customer retention and customer acquisition in those market areas in the Northeast where retail competition is most active, Usource has grown revenues by 31%, to just over $2 million. Usource is also building a multi-year book of revenues, as many customers seek to manage their energy risk by signing longer-term contracts. We expect both these trends to continue in 2006 and beyond.

Unitil has an experienced management team to lead the Company's employees in the successful implementation of its Strategic Plan. These employees are also first rate, and they are loyal.

Our goal is to grow the business 3-5% per year, with continuing improvement in cash flow and operational performance. I believe we have the technology, the tools, the employees, and the resources to make this happen.

Robert Schoenberger

Robert G. Schoenberger
Chairman of the Board of Directors
President & Chief Executive Officer

February 3, 2006

This Annual Report contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity, and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire (State or other jurisdiction of incorporation or organization)	**02-0381573** (I.R.S. Employer Identification No.)
6 Liberty Lane West, Hampton, New Hampshire (Address of principal executive offices)	**03842-1720** (Zip Code)

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**American Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Based on the closing price of June 30, 2005, the aggregate market value of common stock held by non-affiliates of the registrant was $147,884,697.

The number of common shares outstanding of the registrant was 5,618,664 as of February 22, 2006.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 20, 2006, are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2005
Table of Contents

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly-owned subsidiaries of Unitil:

Unitil Corporation Subsidiaries	State and Year of Organization	Principal Type of Business
Unitil Energy Systems, Inc. (UES)	NH - 1901	Retail Electric Distribution Utility
Fitchburg Gas and Electric Light Company (FG&E)	MA - 1852	Retail Electric & Gas Distribution Utility
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-utility, Unregulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering and Advisory Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts. Unitil has two distribution utility subsidiaries, UES, which operates in New Hampshire and FG&E, which operates in Massachusetts (collectively referred to as the "retail distribution utilities"). Unitil's retail distribution utilities serve approximately 98,600 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are local "pipes and wires" utility distribution companies with a combined investment in net utility plant of $213.0 million at December 31, 2005. Unitil's total revenue was $232.1 million in 2005. Earnings applicable to common shareholders for 2005 was $8.4 million. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

OPERATIONS

Electric Utility Operations

Unitil's electric utility operations are conducted through the retail distribution utilities, UES and FG&E. Revenue from Unitil's electric utility operations was $197.3 million for 2005. Earnings from electric utility operations were $7.0 million for the same 12-month period.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its franchise areas. As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities continue to deliver that supply of electricity over their distribution systems. Both UES and FG&E supply electricity to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

UES distributes electricity to approximately 71,100 customers in New Hampshire in the capital city of Concord as well as 12 surrounding towns and all or part of 16 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. UES' franchise areas consist of approximately 408 square miles. The state capital of New Hampshire is located within UES' franchise areas, and includes the executive, legislative and judicial branches and offices and facilities for all major state government services as well as several federal government facilities. In addition, UES' franchise areas are retail trading and recreation centers for the central and southeastern parts of the state. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics. UES' franchise areas include popular resort areas and beaches along the Atlantic Ocean, including the Hampton Beach recreational area. UES' 2005 retail electric operating revenue was $134.7 million, of which approximately 41.0% was derived from residential sales and 59.0% from commercial/industrial sales. UES' earnings in 2005 were $3.8 million.

FG&E is engaged in the retail distribution of both electricity and natural gas in the city of Fitchburg and several surrounding communities. FG&E's franchise area encompasses approximately 170 square miles. Electricity is supplied and distributed by FG&E to approximately 27,500 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. FG&E's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. FG&E's 2005 retail electric operating revenue was $62.6 million, of which approximately 44.0% was derived from residential sales and 56.0% from commercial/industrial sales. FG&E's earnings from electric utility operations were $3.2 million in 2005.

Gas Utility Operations

Natural gas is supplied and distributed by FG&E to approximately 15,000 retail customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

FG&E's 2005 gas operating revenue was $32.8 million, of which approximately 58.0% was derived from residential firm sales and 42.0% from commercial/industrial firm sales. Earnings from FG&E's gas utility operations were $0.9 million for 2005.

Seasonality

Natural gas sales in New England are seasonal, and the Company's results of operations reflect this seasonal nature. Accordingly, results of operations are typically positively impacted by gas operations during the five heating season months, from November through March. Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours.

Non-Utility, Unregulated Operations and Other

Unitil's non-utility, unregulated operations are comprised of Unitil Resources and Usource. Unitil Resources provides energy consulting and management services. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's unregulated operations was $2.0 million in 2005. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries. In addition to the earnings from unregulated operations, the earnings of these subsidiaries are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and is reported in Other segment income. Non-utility, unregulated operations and Other segment earnings for 2005 were approximately $0.5 million.

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)
(For segment information, see Part II, Item 8, Note 10 herein.)

RATES AND REGULATION

Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil's utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third party vendors. Most customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next 5 to 7 years, is $154 million as of December 31, 2005 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

ELECTRIC POWER SUPPLY

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from competitive retail suppliers, though most customers continue to purchase such supplies through the retail distribution utilities. The transition to retail choice required the divestiture of Unitil's existing power supply arrangements and the procurement of replacement supplies which provided the flexibility for migration of customers to and from utility service. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the Independent System Operator—New England (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

Power Supply Divestiture

Prior to May 1, 2003, UES purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, UES and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to UES ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, UES continues to pay contract release payments to Unitil Power for costs associated with the portfolio sale and its other ongoing power supply-related costs. Recovery of the contract release payments by UES from its retail customers has been approved by the NHPUC.

Unitil Power divested its long-term power supply contracts to Mirant Corporation (Mirant). The purchase of power to supply UES' Transition Service and Default Service requirements by UES from Mirant was linked to the Unitil Power divestiture. The NHPUC Order completed the state approval process for Unitil's restructuring plan under which UES implemented customer choice for its customers on May 1, 2003. The divested power supply contracts continue through October 2010.

In March 1999, FG&E completed the sale of its 4.5% interest in the New Haven Harbor Station generating unit. FG&E divested its remaining owned generation assets and long-term power supply contracts to Select Energy, Inc., a subsidiary of Northeast Utilities. Under the Select Energy contract, which was approved by the MDTE in January 2000, and went into effect February 1, 2000, FG&E began selling the entire output from its remaining long-term power supply contracts and the output of its two joint ownership units, Millstone Unit 3 and Wyman Unit No. IV, to Select Energy. Upon the sale of FG&E's share of Millstone Unit 3 in 2001, this portion of the contract sale ceased. Effective with the termination of the Purchased Power Contract between FG&E and Linweave, Inc. on December 1, 2004, this portion of the contract sale also ceased. On December 30, 2005 Select Energy assigned the FG&E contracts portfolio to Constellation Energy Commodities Group (Constellation) effective January 1, 2006. Recovery of all costs associated with the divestiture of the FG&E power supply portfolio has been approved by the MDTE.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into wholesale electric power supply contracts with various wholesale suppliers. In particular, FG&E has entered into power supply contracts to meet its power supply obligations associated with the provision of Standard Offer Service and Default Service. Standard Offer Service was offered only to customers who had both taken service from FG&E since the inception of retail choice in 1998 and had not switched to a competitive retail supplier. Consistent with MDTE regulations, Standard Offer Service ended February 28, 2005. Effective March 1, 2005 FG&E customers are eligible for Default Service. FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service. MDTE policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, with each 12 month contract providing 50% of the class requirements.

The MDTE is investigating alternatives to the current procurement policy for all accounts, other than the large general accounts. This process could potentially lead to the procurement of FG&E Default Service power supply for longer duration in order to provide more price stability for smaller customers throughout Massachusetts for whom competitive retail options are relatively scarce.

UES has entered into a power supply contract to meet its power supply obligations associated with the provision of Transition Service and Default Service. Transition Service is available to any UES customer who has not chosen a competitive retail supplier. UES' Default Service is available to any customer who has chosen a competitive retail energy supplier and returns to retail energy supply from UES. UES has entered into a power supply contract for the provision of Transition Service and Default Service with Mirant. This power supply contract provided fixed unit prices for both Transition Service and Default Service for UES' largest general service accounts through April 2005 and for all other accounts through April 2006.

On July 14, 2003 Mirant filed for Chapter 11 Bankruptcy protection. Mirant is currently performing all of its contractual obligations to both Unitil Power and UES and has satisfied all of its pre-petition claims made by Unitil. On January 3, 2006 Mirant emerged from Chapter 11 Bankruptcy protection.

In January, 2005 the NHPUC approved two six-month supply contracts for Transition Service and Default Service for UES' large general service customers for the period May, 2005 through April, 2006. In September, 2005 the NHPUC approved a Settlement among UES, NHPUC Staff and the Office of Consumer Advocate which provides for UES to procure Default Service for its largest general service accounts through successive competitive solicitations of three-months duration and to procure Default Service for all other customers through a series of two one-year contracts and two three-year contracts with each contract covering 25% of the total requirements of the group. The first two contracts were of 6-months and 18-months duration in order to stagger the start dates of future 1-year and 3-year procurements. On November 2, 2005, the NHPUC approved those two initial Default Service contracts for service starting May 1, 2006.

Regional Transmission and Power Markets

FG&E, UES and Unitil Power are members of the NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by an agreement (NEPOOL Agreement) that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the NEPOOL Open Access Transmission Tariff (OATT), to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations, and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The regional bulk power system is operated by an independent corporate entity, ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a Regional Transmission Organization (RTO) was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO in orders issued March 24, 2004 and November 3, 2004 to begin operation of the RTO structure effective February 1, 2005. As a result of the formation of the RTO, companies seeking transmission service throughout New England will be able to obtain that service under common terms, with much of their focus on dealing with ISO-NE, in cooperation with the local transmission providers.

On March 1, 2004, ISO-NE filed a proposal to implement Locational Installed Capacity (LICAP) in New England to allow for the imposition of incentive pricing for transmission constrained areas. UES and FG&E have intervened in the proceeding. Both UES and FG&E are located in a non-constrained area of the power pool. On October 21, 2005 the FERC issued an order directing that Settlement discussions take place and indicating that implementation of LICAP, if it proceeds, will not be earlier than October 1, 2006. This case is still before the FERC.

The formation of an RTO, LICAP and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDTE and NHPUC.

GAS SUPPLY

FG&E's natural gas customers now have the opportunity to purchase their natural gas supply from third-party vendors, though most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E purchases natural gas from domestic and Canadian suppliers under contracts of one year or less, as well as from producers and marketers on the spot market and arranges for the transportation to its distribution facilities under long-term contracts with the Tennessee interstate pipeline. FG&E has a four-year contract for LNG supply which ends in 2008 which was approved by the MDTE. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2003 through 2005.

Sources of Gas Supply
(Expressed as percent of total MMBtu of gas purchased)

	2005	2004	2003
Natural Gas:			
Domestic firm	**84.8%**	85.0%	94.0%
Canadian firm	**3.4%**	5.4%	1.3%
Domestic spot market	**9.3%**	5.9%	1.3%
Total natural gas	**97.5%**	96.3%	96.6%
Supplemental gas	**2.5%**	3.7%	3.4%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2005	2004	2003
Cost of gas purchased and sold per MMBtu	**$10.83**	$8.42	$7.14
Percent Increase (Decrease) from prior year	**28.7%**	17.9%	43.9%

FG&E has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a liquefied natural gas (LNG) storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of December 31, 2005, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan (MCP) that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed. During 2005, FG&E continued developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

On May 13, 2004 FG&E discovered an unauthorized excavation by another property owner on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated onto property owned by FG&E. FG&E promptly reported this discovery to the DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. The Completion Report for this release was submitted May 9, 2005.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1822 through 1978. In addition, any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

EMPLOYEES

As of December 31, 2005, the Company and its subsidiaries had 310 employees. Management considers the Company's relationship with employees to be good and has not experienced any major labor disruptions since the early 1960's.

There are approximately 100 employees represented by labor unions. These employees are covered by collective bargaining agreements, which expire May 31, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is www.unitil.com. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the American Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 22, 2006:

Name	Age	Position
Robert G. Schoenberger	55	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	46	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	43	Senior Vice President and Chief Operating Officer
Laurence M. Brock	52	Controller and Chief Accounting Officer
Todd R. Black	41	Vice President, Energy Markets
George R. Gantz	54	Senior Vice President, Customer Services and Communications
George E. Long, Jr.	49	Vice President, Administration
Raymond J. Morrissey	58	Vice President, Information Systems
Sandra L. Whitney	42	Corporate Secretary
Dr. Robert V. Antonucci	60	Director
David P. Brownell	62	Director
Michael J. Dalton	65	Director
Albert H. Elfner, III	61	Director
Edward F. Godfrey	56	Director
Michael B. Green	56	Director
Eben S. Moulton	59	Director
M. Brian O'Shaughnessy	62	Director
Charles H. Tenney, III	58	Director
Dr. Sarah P. Voll	63	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board and Chief Executive Officer since 1997 and Unitil's President since 2003. Prior to his employment with Unitil, he was President and Chief Executive Officer of the New York Power Authority (a state owned public power enterprise) from 1993 until 1997. He is also a Trustee and Chairman of Exeter Health Resources.

Mark H. Collin was appointed Unitil's Senior Vice President and Chief Financial Officer in February 2003. Mr. Collin has served as Unitil's Treasurer since 1998. Since 1992, he has been Treasurer of UES and FG&E. Mr. Collin joined Unitil in 1988. Mr. Collin serves on the Board of Governors of New Hampshire Public Television.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President and Chief Operating Officer since June 2005. Mr. Meissner served as Unitil's Senior Vice President, Operations from February 2003 through June 2005. Mr. Meissner joined Unitil in 1994 and served as Unitil's Director of Engineering from 1998 to 2003. From 1985 to 1994, he was employed by the Public Service Company of New Hampshire.

Laurence M. Brock has been Unitil's Chief Accounting Officer and Controller since June 2005. Mr. Brock joined Unitil in 1995 as Vice President and Controller, and is a Certified Public Accountant in the State of New Hampshire. Prior to his employment with Unitil, Mr. Brock served as a Corporate Controller with a group of diversified financial services and manufacturing companies. Mr. Brock gained his public accounting experience with Coopers & Lybrand in Boston, Massachusetts.

Todd R. Black has been Unitil's Vice President, Energy Markets since January 2003. He served as Vice President, Sales and Marketing for Usource from 1998 to 2003. Prior to his employment with Unitil, he served as Vice President, Services Delivery for Energy USA, the unregulated subsidiary of Bay State Gas Company, from 1988 until 1998.

George R. Gantz has been Unitil's Senior Vice President, Customer Services and Communications since January 2003. Mr. Gantz previously served as Unitil's Senior Vice President, Communication and Regulation from 1994 to 2003. Mr. Gantz joined Unitil in 1983.

George E. Long, Jr. has been Unitil's Vice President, Administration since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources from 1998 to 2003. Prior to his employment with Unitil, Mr. Long was the Director of Compensation and Benefits at Monarch Life Insurance Company from 1985 to 1994.

Raymond J. Morrissey has been Unitil's Vice President, Information Systems since February 2003. From 1992 to 2003, he served as Unitil's Vice President of Customer Service, and from 1991 to 1992, he was the General Manager of Unitil's subsidiary, FG&E. Mr. Morrissey joined Unitil in 1985.

Sandra L. Whitney has been Unitil's Corporate Secretary and Secretary of the Board since February 2003. Ms. Whitney has been the Corporate Secretary of Unitil's subsidiary companies, FG&E, UES, Unitil Power, Unitil Realty and Unitil Service since 1994. Ms. Whitney joined Unitil in 1990.

Dr. Robert V. Antonucci has been President of Fitchburg State College since 2003. Dr. Antonucci was also President of the School Group of Riverdeep, Inc from 2001 to 2003, and President and CEO of Harcourt Learning Direct and Harcourt Online College from 1998 to 2001. Dr. Antonucci also served as the Commissioner of Education for the Commonwealth of Massachusetts from 1992 to 1998. Dr. Antonucci also serves as a Director of Eastern Bank.

David P. Brownell was a Senior Vice President of Tyco International Ltd. from 1995 until his retirement in 2003. He had been with Tyco since 1984. Mr. Brownell is also Vice Chairman of the University of New Hampshire Foundation.

Michael J. Dalton was Unitil's President and Chief Operating Officer from 1984 until his retirement in 2003. Mr. Dalton is a member of the Advisory Board of the University of New Hampshire College of Engineering and Physical Sciences.

Albert H. Elfner, III was the Chairman, from 1994, and Chief Executive Officer, from 1995, of Evergreen Investment Management Company until his retirement in 1999. Mr. Elfner is also a Director of NGM Insurance Company (NGM), as well as a member of the NGM Finance Committee, and the Chairman of MDT Funds (formerly Optimum Q Funds.)

Edward F. Godfrey was the Executive Vice President and Chief Operating Officer of Keystone Investments, Incorporated from 1997 until his retirement in 1998. While at Keystone Investments, he was also a Senior Vice President, Chief Financial Officer and Treasurer from 1988 to 1996. Mr. Godfrey is also a Director of Reilly Mortgage Group and serves on their Audit Committee.

Michael B. Green has been the President and Chief Executive Officer of Capital Region Health Care and Concord Hospital since 1992. Mr. Green is also a member of the Adjunct Faculty, Dartmouth Medical School, Dartmouth College. He also currently serves on the Board of the Foundation for Healthy Communities, is a Director and Vice Chair of the New Hampshire Hospital Association, a Director of New Hampshire Business Committee for the Arts, a Director of Merrimack County Savings Bank, including membership on the bank's Investment and Audit Committees, and a member of the *Concord Monitor* Board of Contributors.

Eben S. Moulton has been the Managing Partner of Seacoast Capital Corporation since 1995. Mr. Moulton is also a Director of IEC Electronics, a Director of six private companies and a Trustee of Colorado College.

M. Brian O'Shaughnessy has been the Chairman of the Board, Chief Executive Officer and President of Revere Copper Products, Inc. since 1988. Mr. O'Shaughnessy also serves on the Board of Directors of the National Association of Manufacturers, the International Copper Association, the Copper Development Association, and the Copper and Brass Fabricators Council. He also serves in New York State as Chairman of the Industrial Energy Consumer Coalition, and as a member of the Board of Directors of the Multiple Intervenors.

Charles H. Tenney, III has been Director of Operations for Brainshift.com, Inc. since 2002. He also served as a financial advisor for H&R Block Financial Advisors from 2001 to 2002 and as the Director of Corporate Services for Log On America, Inc. from 1999 to 2000. Mr. Tenney also currently serves on the Board of Overseers of the Huntington Theater Company, Boston, Massachusetts.

Dr. Sarah P. Voll has been the Vice President, National Economic Research Associates, Inc. ("NERA") since 1999. Dr. Voll was also a Senior Consultant at NERA from 1996 to 1999.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 20, 2006, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of stock certificates, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Mail: Computershare, P.O. Box 43010, Providence, RI 02940-3010

Telephone: 800-736-3001 (Outside MA); 781-575-3100 (Within MA)

Investor Relations

For information about the Company and your investment, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at *www.unitil.com*; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available

- Internet Account Access is available at *www.computershare.com/equiserve*.

- Dividend Reinvestment Plan:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.

- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.

- Direct Registration:

  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

Risks related to the regulation of our business could impact the rates we are able to charge, our costs and our profitability.

We are subject to comprehensive regulation by federal and state regulatory authorities, which significantly influences our operating environment and our ability to recover costs from our customers. In particular, we are regulated by the FERC and state regulatory authorities with jurisdiction over public utilities, including the NHPUC and the MDTE. These authorities regulate many aspects of our operations, including, but not limited to, construction and maintenance of facilities, operations, safety, issuance of securities, accounting matters, transactions between affiliates, the rates that we can charge customers and the rate of return that we are allowed to realize. Our ability to obtain rate adjustments to maintain our current rate of return depends upon regulatory action under applicable statutes, rules and regulations, and we cannot assure you that we will be able to obtain rate adjustments or continue receiving our current authorized rates of return. These regulatory authorities are also empowered to impose financial penalties and other sanctions on us if we are found to have violated statutes and regulations governing our utility operations.

We are unable to predict the impact on our operating results from the regulatory activities of any of these agencies. Although we have attempted to actively manage the rate making process and have had recent success in obtaining rate increases, we can offer no assurances as to future success in the rate making process. Despite our requests, these regulatory commissions have authority under applicable statutes, rules and regulations to leave our rates unchanged, grant increases or order decreases in such rates. They have similar authority with respect to the recovery of our electricity and natural gas supply costs incurred by UES and FG&E in their role as a "provider of last resort" for customers who do not contract with third-party suppliers, or whose third-party supplier fails to deliver. In the event that we are unable to recover these costs or recovery of these costs were to be significantly delayed, our operating results could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have an adverse effect on our operating results.

As a result of industry restructuring, we have a significant amount of certain stranded and energy supply costs, which are subject to recovery in future periods.

The stranded costs resulting from the implementation of industry restructuring mandated by the states of New Hampshire and Massachusetts and the cost of purchased power we incur as the "provider of last resort" on behalf of our customers are recovered by us on a pass-through basis through periodically adjusted rates. Any unrecovered balance of purchased power or stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

Our power supply portfolio related stranded costs due to the electric industry restructuring in New Hampshire and Massachusetts for which regulatory approval has been obtained for recovery were approximately $57.9 million for FG&E and $57.0 million for UES as of December 31, 2005. Substantially all of FG&E's stranded costs relate to owned generation assets and long-term power purchase agreements divested by FG&E to Select Energy. Approximately $57.6 million of UES' stranded costs are attributable to the long-term power purchase agreements divested by Unitil Power to Mirant. Because FG&E and Unitil Power remain ultimately responsible for payments under the power purchase agreements divested by them, if either Select or Mirant were to fail to fulfill their obligations to purchase the entitlements to electricity provided for in those agreements, FG&E and Unitil Power could incur additional stranded costs were they to resell such entitlements for amounts less than the amounts agreed to be paid by Select and Mirant. We expect that any such additional stranded costs would be recovered from our customers, although such recovery would require approval from the MDTE or NHPUC, the receipt of which cannot be assured.

Our electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may negatively impact our customers and correspondingly our operating results and financial condition.

Our business is influenced by the economic activity of our franchise areas. The level of economic growth in our electric and natural gas distribution franchise areas directly affects our potential for future growth in our business. As a result, adverse changes in the economy may have negative effects on our revenues, operating results and financial condition.

Declines in the valuation of capital markets could require us to make substantial cash contributions to cover our pension obligations, which could negatively impact our financial condition. In addition, the recovery of certain pension obligations is subject to regulatory risks.

We made voluntary cash contributions to our pension plans of $1.2 million and $2.0 million in 2003 and 2004, respectively. In 2005 we were required to make a minimum cash contribution of $0.7 million to our pension plans and made an additional voluntary cash contribution of $1.8 million for a total of $2.5 million. If the valuation of capital markets were to significantly decline from current levels, we may be required to make cash contributions to our pension plans substantially in excess of the levels currently anticipated, which could adversely affect our financial condition.

Increases in interest rates could have a negative impact on our financial condition.

Our subsidiaries have ongoing capital expenditure requirements which they frequently fund through borrowings from outside lenders. Changes in interest rates do not affect interest expense associated with our subsidiaries' presently outstanding fixed rate long-term debt securities. However, our subsidiaries periodically issue new long-term debt securities either to refinance short-term borrowings or to fund capital expenditures. Changes in interest rates may affect the interest rate and corresponding interest expense on any such new long-term debt securities. In addition, our subsidiaries' short-term borrowings are at variable rates of interest. As a result, changes in short-term interest rates will increase or decrease our interest expense associated with short-term borrowings. Increases in interest rates generally will increase our borrowing costs and could adversely affect our financial condition or results of operations.

Weather conditions may cause our sales to vary from year to year.

Our utility operating sales vary from year to year, depending on weather conditions. We estimate that approximately 75% of our annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, particularly during the winter heating season. Our electric sales are generally less sensitive to weather than our gas sales, but may also be affected by weather conditions in both the winter and summer seasons.

We are a holding company and have no operating income of our own. Our ability to pay dividends on our common stock is dependent on dividends received from our subsidiaries and on factors directly affecting us, the parent corporation. We cannot assure you that our current annual dividend will be paid in the future.

We are a public utility holding company and we do not have any operating income of our own. Consequently, our ability to pay dividends on our common stock is dependent on dividends and other payments received from our subsidiaries, principally UES and FG&E. Our subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to us, whether through dividends, loans or other payments. The ability of our subsidiaries to pay dividends or make distributions to us will depend on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of our subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by our subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of UES and FG&E and that may be contained in future debt agreements of our subsidiaries, if any;
- limitations imposed by New Hampshire and Massachusetts state regulatory agencies, which, among other things, may prohibit the payment of dividends by subsidiaries out of capital or unearned surplus without prior approval.

In addition, we may incur indebtedness in the future. Before we can pay dividends on our common stock, we have to satisfy our debt obligations and comply with any statutory or contractual limitations.

Our current annual dividend is $1.38 per share of common stock, payable quarterly. However, our board of directors reviews our dividend policy periodically in light of the factors referred to above, and we cannot assure you of the amount of dividends, if any, that may be paid in the future.

Transporting and storing natural gas and supplemental gas supplies, as well as electricity, involve numerous risks that may result in accidents and other operating risks and costs.

Inherent in our electric and gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions, electrocutions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, and impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines, storage facilities and electric distribution equipment near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

Our business is subject to environmental regulation in all jurisdictions in which we operate and our costs of compliance are significant. Any changes in existing environmental regulation and the incurrence of environmental liabilities could negatively affect our results of operations and financial condition.

Our utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and the health and safety of our employees. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; imposition of remedial requirements; and even issuance of injunctions to ensure future compliance. Liability under certain environmental laws is strict, joint and several in nature. Although we believe we are in general compliance with all applicable environmental and safety laws and regulations, there can be no assurance that significant costs and liabilities will not be incurred in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, could result in increased environmental compliance costs. See “Environmental Matters” in the Part I, Item 1, “Business” section of this report for further detail.

Catastrophic events could have a material adverse effect on our financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could have a material adverse effect on us, since they could inhibit our ability to continue providing electric and/or gas distribution services to our customers for an extended period, which is the principal source of our operating income.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2005, Unitil owned, through its retail distribution utilities: two operation centers, approximately 2,145 pole miles of local transmission and distribution overhead electric lines and 507 conduit bank miles of underground electric distribution lines, along with 55 electric substations, including three mobile electric substations. FG&E's natural gas operations property includes a liquid propane gas plant, a liquid natural gas plant and 316 miles of underground gas mains. In addition, Unitil's real estate subsidiary, Unitil Realty, owns the Company's corporate headquarters building and the 12 acres on which it is located in Hampton, New Hampshire.

UES owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. UES' 34 electric distribution substations, including a 5,000 kilovolt ampere (kVA) mobile substation, constitute 233,237 kVA of capacity (includes spares and mobile) for the transformation of electric energy from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by UES or occupied by UES pursuant to a perpetual easement.

UES has a total of approximately 1,590 pole miles of local transmission and distribution overhead electric lines and a total of 336 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by UES without objection by the owners. In the case of certain distribution lines, UES owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

Additionally, UES owns 137.7 acres of non-utility property located on the east bank of the Merrimack River in Concord, New Hampshire. Of the total acreage, 81.2 acres are located within an industrial park zone.

The physical utility properties of UES, with certain exceptions, and its franchises are pledged as security under its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of UES are outstanding.

FG&E's electric properties consist principally of 555 pole miles of local transmission and distribution overhead electric lines, 171 conduit bank miles of underground electric distribution lines and 21 transmission and distribution stations including two mobile electric substations. The capacity of these substations totals 562,650 kVA.

FG&E owns a liquid propane gas plant and a liquid natural gas plant and the land on which they are located. FG&E also has 316 miles of underground steel, cast iron and plastic gas mains.

FG&E's electric substations, with minor exceptions, are located on land owned by FG&E or occupied by FG&E pursuant to a perpetual easement. FG&E's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by FG&E without objection by the owners. FG&E leases its distribution operations center located in Fitchburg, Massachusetts.

Management believes that the Company's facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Note 5 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 4. Submission of Matters to a Vote of Security Holders

None

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's Common Stock is traded on the American Stock Exchange. As of December 31, 2005, there were 1,847 Common Shareholders of record.

Common Stock Data

Dividends per Common Share	2005	2004
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

Price Range of Common Stock	2005 High/Ask	2005 Low/Bid	2004 High/Ask	2004 Low/Bid
1st Quarter	**$27.80**	**$25.50**	$27.72	$25.60
2nd Quarter	**$28.05**	**$25.31**	$28.25	$25.33
3rd Quarter	**$28.70**	**$27.00**	$27.24	$25.56
4th Quarter	**$28.10**	**$24.37**	$28.75	$27.08

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

EQUITY COMPENSATION PLAN BENEFIT INFORMATION

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
KESOP (1)	38,202	$11.89	29,101
Restricted Stock Plan (2)	—	N/A	130,925
Equity compensation plans not approved by security holders			
1998 Option Plan (3)	107,000	$27.13	—
Total	145,202	$23.12	160,026

NOTES: (also see Note 2 to the Consolidated Financial Statements)

(1) The KESOP was approved by shareholders in July 1989. Options were granted between January 1989 and November 1997.

(2) The Restricted Stock Plan was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006.

(3) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the Option Plan were deregistered with the Securities and Exchange Commission. The Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the Option Plan. No further grants of options will be made thereunder.

Unregistered Sales of Equity Securities and Uses of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2005.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
10/1/05 – 10/31/05	—	—	—	n/a
11/1/05 – 11/30/05	—	—	—	n/a
12/1/05 – 12/31/05	93	$24.90	93	n/a
	2,174	$25.29	2,174	
Total	2,267	$25.28	2,267	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

Item 6. Selected Financial Data

For the Years Ended December 31,	2005	2004	2003	2002	2001
(all data in thousands except % and per share data)					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 232,145**	$ 214,137	$ 220,654	$ 188,386	$ 207,022
Operating Income	**15,541**	15,193	15,449	13,248	14,394
(Gain) Loss on Non-Utility Investments, net of tax	**—**	—	—	(82)	2,400
Other Non-operating Expense	**147**	193	(40)	185	170
Income Before Interest Expense and Extraordinary Item	**15,394**	15,000	15,489	13,145	11,824
Interest Expense, net	**6,841**	6,774	7,531	7,057	6,797
Income before Extraordinary Item	**8,553**	8,226	7,958	6,088	5,027
Extraordinary Item, net of tax	**—**	—	—	—	3,937
Net Income	**8,553**	8,226	7,958	6,088	1,090
Dividends on Preferred Stock	**156**	215	236	253	257
Earnings Applicable to Common Shareholders	**$ 8,397**	$ 8,011	$ 7,722	$ 5,835	$ 833
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 324,967**	$ 308,054	$ 288,657	$ 272,402	$ 255,498
Total Assets	**$ 450,081**	$ 457,010	$ 483,877	$ 481,702	$ 376,762
Capitalization:					
Common Stock Equity	**$ 96,283**	$ 94,291	$ 92,805	$ 74,350	$ 74,746
Preferred Stock	**2,327**	2,338	3,269	3,322	3,609
Long-Term Debt, less current portion	**125,365**	110,675	110,961	104,226	107,470
Total Capitalization	**$ 223,975**	$ 207,304	$ 207,035	$ 181,898	$ 185,825
Current Portion of Long-Term Debt	**$ 308**	$ 285	$ 3,263	$ 3,243	$ 3,224
Short-term Debt	**$ 18,700**	$ 25,675	$ 22,410	$ 35,990	$ 13,800
Capital Structure Ratios:					
Common Stock Equity	**43%**	46%	45%	41%	40%
Preferred Stock	**1%**	1%	2%	2%	2%
Long-Term Debt	**56%**	53%	53%	57%	58%
Earnings Per Share Data:					
Earnings Per Average Share – Basic and Diluted	**$ 1.51**	$ 1.45	$ 1.58	$ 1.23	$ 0.18
Common Stock Data:					
Shares of Common Stock – Diluted (Average)	**5,568**	5,525	4,896	4,762	4,760
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.21**	$ 17.00	$ 16.87	$ 15.67	$ 15.76
Electric and Gas Sales:					
Electric Distribution Sales (kWh)	**1,790,405**	1,742,131	1,717,664	1,659,136	1,596,390
Firm Natural Gas Distribution Sales (Therms)	**24,332**	23,151	24,592	22,480	23,067

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

Forward-Looking Information

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding Management's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Increased competition; and
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A. Risk Factors.

EARNINGS & DIVIDENDS

The Company's Earnings Applicable to Common Shareholders was $8.4 million for 2005, an increase of $0.4 million, or 4.8%, compared to 2004. Earnings per common share were $1.51 for 2005, an increase of $0.06 per share compared with earnings of $1.45 per share for 2004. Earnings for 2005 reflect higher electric sales, driven by customer growth and hotter summer weather in 2005, and higher gas sales reflecting a new contract with a large industrial customer. Unitil also recorded higher net operating costs in 2005 compared to 2004.

Total electric kilowatt-hour (kWh) sales increased by 2.8% in 2005 compared to 2004. The Company's service territories experienced hotter weather during the summer of 2005 compared to the same period in 2004. Also contributing to the increase in unit sales was continued growth in the number of customers served.

Total firm therm natural gas sales increased by 5.1% in 2005 compared to 2004. This increase was due to a new contract with a large industrial customer.

Combined electric and gas sales margins increased $1.5 million in 2005 compared to 2004. The increases in electric and gas sales margins reflect increases in electric and gas sales in addition to increased utility rates authorized by regulators.

Total O&M expense increased $1.2 million, or 5.2%, in 2005 compared to 2004. This increase reflects higher salaries and compensation expenses of $0.6 million, higher retiree and employee benefit costs of $0.5 million, higher audit fees of $0.2 million, higher utility operating and maintenance expenses of $0.1 million and higher bad debt expenses of $0.1 million, partially offset by lower administrative and general expenses of $0.3 million. The higher audit fees include expenditures to comply with Section 404 of the Sarbanes-Oxley Act of 2002 (SOXA).

Depreciation and Amortization expense increased $0.3 million, or 1.6%, in 2005 compared to 2004, reflecting higher depreciation expense of $0.6 million, due to increased investment in utility plant additions, partially offset by lower amortization in 2005 on the Company's regulatory assets related to its former abandoned property investment in Seabrook Station, which became fully-amortized in the third quarter of 2005.

Interest Expense, net increased $0.1 million, or 1.0% in 2005 compared to 2004. This increase was driven by increases in interest expense on short-term borrowings partially offset by increases in interest income, primarily due to increased carrying charges on regulatory assets.

In 2005, Unitil's annual common dividend was $1.38. At its January, 2006 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

Per Share Data	2005	2004	2003
Earnings per Common Share	**$1.51**	$1.45	$1.58
Annual Dividend	**$1.38**	$1.38	$1.38

A more detailed discussion of the Company's 2005 Results of Operations and a year-to-year comparison of changes in financial position for the three-year period 2003 through 2005 are presented below.

RESULTS OF OPERATIONS

Operating Revenue—Electric

Electric Operating Revenue—Electric Operating Revenue increased by $13.4 million, or 7.3%, in 2005 as compared to 2004. Electric Operating Revenue includes the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in operating expenses. The increase in Electric Operating Revenue primarily reflects an increase in Purchased Electricity costs and electricity unit sales volumes compared to the prior period. The Purchased Electricity cost of sales component increased $12.2 million, or 9.7%, in 2005 as compared to 2004, due to higher wholesale electric commodity prices. Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. The Company recovers the cost of Purchased Electricity in its rates at cost on a pass through basis. C&LM revenue related to electric operations increased $0.3 million, or 9.0% in 2005 as compared to 2004. The Company also recovers the costs of C&LM on a pass through basis.

Gross electric sales margin (Electric Operating Revenue less Cost of Electric Sales) was $55.4 million in 2005. This represents an increase of $0.9 million compared to 2004. This increase reflects increased kWh unit sales to both residential and commercial and industrial customer classes and higher base rates as discussed above, partially offset by the expiration in 2005 of a rate surcharge on Regulatory Assets.

In 2004, Electric Operating Revenue decreased by $7.0 million, or 3.7% compared to 2003. The Purchased Electricity cost of sales component decreased $8.1 million, or 6.0% in 2004 compared to 2003, reflecting lower electric wholesale commodity prices. Electric sales margin was $54.4 million in 2004, an increase of $1.2 million over 2003. This increase reflects increased kWh unit sales to both residential and commercial and industrial customer classes.

The following table details total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenue and Sales Margin (000's)

	2005	2004	2003	% Change 2005 vs. 2004	% Change 2004 vs. 2003
Electric Operating Revenue:					
Residential	**$ 82,244**	$ 75,689	$ 76,893	8.7%	(1.6%)
Commercial/Industrial	**115,094**	108,200	113,971	6.4%	(5.1%)
Total Electric Operating Revenue	**$197,338**	$183,889	$190,864	7.3%	(3.7%)
Cost of Electric Sales:					
Purchased Electricity	**$138,134**	$125,940	$134,036	9.7%	(6.0%)
Conservation & Load Management	**3,845**	3,527	3,643	9.0%	(3.2%)
Gross Electric Sales Margin	**$ 55,359**	$ 54,422	$ 53,185	1.7%	2.3%

Kilowatt-hour Sales—Unitil's total kWh sales increased 2.8% in 2005 compared to 2004. This increase reflects growth in sales to residential and commercial customers primarily due to hotter summer weather and an increase in the number of customers served in 2005 than in 2004.

Sales to residential customers increased 5.4% in 2005 compared to 2004, due to customer growth and hotter weather. Sales to commercial and industrial (C&I) customers increased 1.2% in 2005 compared to 2004, due primarily to customer growth and the hotter summer weather. The hotter summer temperatures in the Company's service territories resulted in increased usage of electricity for air conditioning and other cooling purposes. According to ISO-NE, the entity which operates the regional bulk power system, New England's electricity use reached an all-time high on July 27, 2005. Our service territories hit two all-time system load peaks on July 19, 2005 and July 27, 2005.

Unitil's total electric kilowatt-hour (kWh) sales increased by 1.4% in 2004 compared to 2003. This increase reflects growth in sales to residential and commercial and industrial customer classes driven by customer growth year over year.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (000's)

	2005	2004	2003	% Change 2005 vs. 2004	% Change 2004 vs. 2003
Residential	**688,318**	652,763	645,711	5.4%	1.1%
Commercial/Industrial	**1,102,087**	1,089,368	1,071,953	1.2%	1.6%
Total	**1,790,405**	1,742,131	1,717,664	2.8%	1.4%

Operating Revenue—Gas

Gas Operating Revenue—Gas Operating Revenue increased $4.1 million, or 14.2%, in 2005 compared to 2004. Gas Operating Revenue includes the recovery of the costs of gas sales, which are recorded as Purchased Gas and C&LM in operating expenses.

Purchased Gas increased $3.7 million, or 21.4%, in 2005 compared to 2004. The increase in Purchased Gas is attributable to higher gas commodity costs. Purchased Gas costs include the cost of gas supply as well as the other energy supply related costs. The Company recovers the cost of Purchased Gas in its rates at cost on a pass through basis. C&LM expenses related to gas operations decreased $0.2 million in 2005 compared to 2004. The Company also recovers the costs of C&LM on a pass through basis.

Gross gas sales margin (Gas Operating Revenue less the Costs of Gas Sales) was $11.3 million in 2005. This represents an increase of $0.6 million compared to 2004. Approximately 22% of the increase in gross gas sales margin is attributable to a 5.1% increase in firm therm sales. This increase in firm therm sales is due to a new firm transportation contract with a large industrial customer. The remaining increase in gas sales margin is attributable to higher rates authorized by regulators to recover certain post retirement benefit costs.

Gas sales margin was $10.7 million in 2004. This represents a decrease of $0.2 million compared to 2003. Total firm therm unit sales decreased 5.9% in 2004 compared to 2003 reflecting milder winter weather in 2004 compared to 2003.

The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenue and Sales Margin (000's)

				% Change	
	2005	**2004**	**2003**	**2005 vs. 2004**	**2004 vs. 2003**
Gas Operating Revenue:					
Residential	**$18,977**	$16,313	$16,267	16.3%	0.3%
Commercial/Industrial	**13,644**	12,323	11,979	10.7%	2.9%
Total Firm Gas Revenue	**$32,621**	$28,636	$28,246	13.9%	1.4%
Interruptible Gas Revenue	**147**	49	366	200.0%	(86.6%)
Total Gas Operating Revenue	**$32,768**	$28,685	$28,612	14.2%	0.3%
Cost of Gas Sales:					
Purchased Gas	**$21,225**	$17,486	$17,421	21.4%	0.4%
Conservation & Load Management	**270**	476	287	(43.3%)	66.0%
Gross Gas Sales Margin	**$11,273**	$10,723	$10,904	5.1%	(1.7%)

Therm Sales—Unitil's total firm therm sales of natural gas increased 5.1% in 2005 compared to 2004, due to a new sales contract with a large industrial customer. Sales to residential customers decreased 2.7% in 2005 compared to 2004 due to a milder winter heating season in 2005 compared to the prior year. Sales to C&I customers increased 12.6% in 2005 compared to 2004. Absent the sales from the new contract discussed above, sales to C&I customers were 2.9% lower in 2005 compared to 2004 due to a milder winter heating season and lower natural gas usage by our largest customers for production processes.

In 2004, total firm therm sales decreased 5.9% compared to 2003, due to a milder winter heating season in early 2004 and lower average natural gas usage by our largest customers year over year.

The following table details total firm therm sales for the last three years, by major customer class:

Firm Therm Sales (000's)

				% Change	
	2005	**2004**	**2003**	**2005 vs. 2004**	**2004 vs. 2003**
Residential	**11,011**	11,319	12,181	(2.7%)	(7.1%)
Commercial/Industrial	**13,321**	11,832	12,411	12.6%	(4.7%)
Total	**24,332**	23,151	24,592	5.1%	(5.9%)

Operating Revenue—Other

Total Other Revenue increased $0.5 million, including a 31% increase in revenue from the Company's energy brokering business, Usource, in 2005 compared to 2004. Total Other Revenue increased $0.4 million in 2004 compared to 2003, including an increase of 36.1% in revenue from Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (000's)

				% Change	
	2005	**2004**	**2003**	**2005 vs. 2004**	**2004 vs. 2003**
Usource	**$2,039**	$1,563	$1,148	30.5%	36.1%
Other	**—**	—	30	—	—
Total Other Revenue	**$2,039**	$1,563	$1,178	30.5%	32.7%

Operating Expenses

Purchased Electricity—Purchased Electricity includes the cost of electric supply as well as the other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity increased $12.2 million, or 9.7%, in 2005 compared to 2004, due primarily to higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not affect earnings.

In 2004, Purchased Electricity expenses decreased $8.1 million, or 6.0%, compared to 2003, reflecting lower electric commodity prices.

Purchased Gas—Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $3.7 million, or 21.4%, in 2005 compared to 2004. The increase in Purchased Gas is attributable to higher natural gas commodity costs. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

In 2004, Purchased Gas increased by $0.1 million, or 0.4%, compared to 2003, reflecting higher natural gas commodity costs.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expense increased $1.2 million, or 5.2%, in 2005 compared to 2004.

This increase reflects higher salaries and compensation expenses of $0.6 million, higher retiree and employee benefit costs of $0.5 million, higher audit fees of $0.2 million, higher utility operating and maintenance expenses $0.1 million and higher bad debt expenses of $0.1 million, partially offset by lower administrative and general expenses of $0.3 million. The higher audit fees include expenditures to comply with Section 404 of the Sarbanes Oxley Act of 2002.

In 2004, total O&M expense increased $0.6 million, or 2.6%, compared to 2003, primarily reflecting higher salaries and compensation expenses of $0.6 million, higher employee benefits costs of $0.6 million, and higher audit, regulatory and professional fees of $0.2 million. These increases were partially offset by lower utility operating and maintenance costs, $0.5 million and lower other expenses, net of $0.3 million.

Conservation & Load Management—Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs.

Energy Efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total Conservation & Load Management expenses increased $0.1 million, or 2.8%, in 2005 compared to 2004. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total Conservation & Load Management expenses increased $0.1 million, or 1.9%, in 2004 compared to 2003.

Depreciation, Amortization and Taxes

Depreciation and Amortization—Depreciation and Amortization expense increased $0.3 million, or 1.6%, in 2005 compared to 2004, reflecting higher depreciation expense of $0.6 million, due to increased investment in utility plant additions, partially offset by lower amortization in 2005 on the Company's regulatory assets related to its former abandoned property investment in Seabrook Station, which became fully-amortized in the third quarter of 2005.

In 2004, Depreciation and Amortization expense increased $0.1 million, or 0.4%, compared to 2003, due to the increased investment in utility plant additions partially offset by lower amortization in 2004 on intangible assets.

Local Property and Other Taxes—Local Property and Other Taxes increased by less than $0.1 million, or 0.7%, in 2005 compared to 2004. This increase was due to higher local property tax rates on higher levels of utility plant in service.

In 2004, Local Property and Other Taxes increased by $0.4 million, or 7.8% compared to 2003. This increase was related to higher local property tax rates coupled with higher levels of utility plant in service.

Federal and State Income Taxes—Federal and State Income Taxes increased $0.1 million, or 1.6%, in 2005 compared to 2004, and by $0.7 million, or 18.4%, in 2004 compared to 2003. These increases were related to higher pre-tax operating income year over year.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and interest on regulatory liabilities. Interest income is mainly derived from carrying charges on restructuring related stranded costs and other deferred costs recorded as regulatory assets by the retail distribution utilities as approved by regulators in New Hampshire and Massachusetts. Over the long run, as deferred costs are recovered through rates, the interest costs associated with these deferrals are expected to decrease together with a decrease in interest income. A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (000's)	2005	2004	2003
Interest Expense			
Long-term Debt	**$ 8,423**	$ 8,492	$ 8,170
Short-term Debt	**1,046**	629	1,071
Subtotal Interest Expense	**9,469**	9,121	9,241
Interest Income			
Regulatory Assets	**(2,525)**	(2,310)	(1,657)
AFUDC and Other	**(103)**	(37)	(53)
Subtotal Interest Income	**(2,628)**	(2,347)	(1,710)
Total Interest Expense, net	**$ 6,841**	$ 6,774	$ 7,531

In 2005, Interest Expense, net, increased by approximately by $0.1 million compared to 2004. The net change in Interest Expense, net, reflects higher variable interest costs on short-term debt, partially offset by higher interest income from carrying charges on regulatory assets. A rise in bank borrowing rates and average daily bank borrowings during 2005 drove Interest Expense on short-term debt.

In 2004, Interest Expense, net, declined by approximately $0.8 million compared to 2003. The reduction in Interest Expense, net, is mainly due to the increase in interest income of $0.7 million during 2004, principally related to carrying charges applicable to regulatory assets. These gains were partially offset by increased interest expense on long-term debt of $0.3 million. In addition, interest expense on short-term debt decreased $0.4 million due to lower levels of average short-term borrowings outstanding.

Capital Requirements and Liquidity

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. At December 31, 2005, Unitil had an aggregate of $44.0 million in unsecured revolving lines of credit with three banks. The Company anticipates that it will be able to secure renewal or replacement of some or all of its revolving lines of credit, in accordance with projected requirements. The Company had short-term debt outstanding through bank borrowings of approximately $18.7 million and $25.7 million at December 31, 2005 and December 31, 2004, respectively. In addition, Unitil had approximately $3.2 million in cash at December 31, 2005. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term lives of its utility assets.

The maximum amount of short-term borrowings that may be incurred by Unitil and its subsidiaries has been subject to periodic approval by the SEC under the Public Utility Holding Company Act of 1935 and state regulators of the Company's retail distribution utilities, UES and FG&E. However, in 2005 the Public Utility Holding Company Act of 1935 (PUHCA) was repealed. Under the Energy Policy Act of 2005 many regulatory oversight responsibilities of the SEC, prior to the repeal of PUHCA were transferred to the FERC. The FERC's transition rule permits Unitil and its subsidiaries to rely on outstanding SEC orders issued under PUHCA, including an order related to Unitil's cash pooling and loan arrangement and certain maximum borrowing authorizations to be extended through December 31, 2007. At December 31, 2005, Unitil had regulatory authorization to incur total short-term bank borrowings up to a maximum of $55 million, and UES and FG&E had regulatory authorizations to borrow up to a maximum of $16 million and $35 million, respectively. In 2005, UES and FG&E had average short-term debt outstanding of $3.2 million and $25.7 million, respectively.

Unitil and its subsidiaries are individually and collectively members of the Unitil Cash Pool. The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool Agreement allows an efficient exchange of cash among Unitil and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on Unitil's actual interest costs from its banks under the revolving lines of credit. In addition, Unitil has been required by the SEC to maintain a minimum 30% common equity ratio, including short-term debt, in order to utilize the Cash Pool. At December 31, 2005, all Unitil subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

During December, 2005, FG&E issued and sold $15.0 million of 5.90% unsecured long-term notes under a debenture note structure (see Note 3). The proceeds were utilized to repay outstanding short-term indebtedness of FG&E. In 2003, FG&E issued $10.0 million in long-term notes under a debenture note structure (see Note 3). The Company expects to continue to be able to satisfy its external financing needs by utilizing additional short-term bank borrowings and to periodically replace short-term debt with long-term financings.

On October 29, 2003, the Company raised approximately $16.9 million (after deducting underwriting discounts and commissions and the estimated expenses of the offering) through the sale of 717,600 shares of its common stock at a price of $25.40 per share in a registered public offering. The offering was increased from an original 520,000 shares to reflect a 20% upsizing of the transaction (104,000 shares) and the exercise of a 15% underwriters' over-allotment (93,600 shares). The Company used the proceeds from this offering to make capital contributions of $6 million to UES and $6 million to FG&E and for other general corporate purposes.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

Benefit Plan Funding

In 2005, 2004 and 2003, the Company and its subsidiaries made cash contributions to their pension plans in the amounts of $2.5 million, $2.0 million and $1.2 million, respectively. The Company may elect to fund the pension plan in future periods. In January 2004, Unitil established Voluntary Employee Benefit Trusts (VEBT) to provide post-retirement benefits. In 2005 and 2004, the Company and its subsidiaries contributed approximately $2.5 million and $2.4 million, respectively to the VEBT and expects to continue to make contributions to the VEBT in future years in amounts consistent with the amounts recovered in retail distribution utility rates for these benefit costs. Prior to the establishment of the VEBT, post-retirement benefits for employees of the Company and its subsidiaries were funded through contributions to the Unitil Retiree Trust (URT). (See Note 8).

Off-Balance Sheet Arrangements

The Company does not currently use, and is not dependent on the use of off-balance sheet financing arrangements, such as securitization of receivables, or obtaining access to assets or cash through special purpose entities or variable interest entities. The Company does have an operating lease agreement with a major financial institution. The operating lease is used to finance the Company's utility vehicles. (See Note 3).

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2005.

Significant Contractual Obligations (000's) as of December 31, 2005	Total	Payments Due by Period 2006	2007-2008	2009-2010	2011 & Beyond
Long-term Debt	$125,673	$ 308	$ 700	$ 821	$123,844
Capital Lease	645	291	342	11	1
Operating Leases	2,739	390	780	751	818
Power Supply Contract Obligations—MA	57,891	7,904	16,137	16,655	17,195
Power Supply Contract Obligations—NH	57,015	13,847	23,807	14,535	4,826
Gas Supply Contracts	23,612	19,989	2,734	790	99
Total Contractual Cash Obligations	$267,575	$42,729	$44,500	$33,563	$146,783

The Company has material energy supply commitments that are discussed in Note 4. Cash outlays for the purchase of electricity and natural gas to serve our customers are subject to full recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over collected cash over subsequent 6-12 month periods.

The Company also provides limited guarantees on certain electric supply contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2005 there are $6.0 million of guarantees outstanding and these guarantees extend through October 24, 2007.

Financial Covenants and Restrictions

The agreements under which the long-term debt of the retail distribution utilities, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Indenture Agreements further require that if UES defaults on any FMB securities, it would constitute a default for all UES FMB securities. The default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

FG&E utilizes a debenture structure of long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Indenture Agreements, FG&E agreements require that if FG&E defaults on any long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

In addition, the UES and FG&E long-term debt instruments and agreements contain certain restrictions on the payment of common dividends from Retained Earnings. On December 31, 2005, UES and FG&E had unrestricted Retained Earnings of $13,300,000 and $7,842,000, respectively, available for the payment of common dividends. (See Note 3). UES and FG&E pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil shareholders.

Unitil Corporation has no long-term debt outstanding. The long-term debt and preferred stock of UES and FG&E are privately held, and the Company does not issue commercial paper. For these reasons, these securities of Unitil and its subsidiaries are not publicly rated.

Results of Operations—Cash Flows

Cash Provided by Operating Activities—Cash provided by operating activities was $24.1 million in 2005, a decrease of $6.6 million compared to 2004. This decrease is due to changes in the Company's working capital requirements. Uses of cash for Accounts Receivable increased by $4.9 million due to higher receivable balances at year-end related to higher energy costs in 2005. Sources of cash from Accounts Payable increased by $3.1 million, due to payables on higher year over year wholesale energy contracts. Sources of cash from Prepayments and Other decreased by $4.2 million in 2005, compared to 2004, primarily related to prepayments to wholesale electricity suppliers made in 2003 that were applied in 2004. Income tax payments increased by $3.6 million in 2005 compared to the previous fiscal year. Sources of cash from Other, net increased by $4.1 million in 2005 compared to 2004, due to a refund to customers in 2004 of $1.2 million and an increase of $2.9 million in liabilities related to the Company's retiree benefit plans and other liabilities in 2005. All other changes in cash flows from operating activities were a net increase of $1.1 million in uses of cash in 2005 compared to 2004.

Cash flows from operating activities of $30.6 million increased by $15.0 million in 2004 compared to 2003. This increase is due to changes in the Company's working capital requirements. Sources of cash from Accrued Revenues increased $7.1 million, principally due to the recovery of 2003 deferred energy costs. In addition, sources of cash from Prepayments and Other increased $8.8 million in 2004 compared to 2003, primarily related to prepayments to wholesale electricity suppliers made in 2003 that were applied in 2004. All other changes in cash flows from operating activities were a net increase of ($0.8 million) in uses of cash in 2004 compared to 2003.

	2005	2004	2003
Cash Provided by Operating Activities (000's)	**$24,076**	$30,648	$15,621

Cash (Used in) Investing Activities—Cash flows used in investing activities increased by $1.4 million in 2005 compared to 2004, and by $1.0 million in 2004 as compared to 2003. Cash used in investing activities is primarily for capital expenditures related to UES' and FG&E's electric and gas distribution systems. Capital expenditures are projected to be $37.2 million in 2006, reflecting normal electric and gas utility system additions and a $10.8 million expenditure for the initial phase of the Company's Automated Metering Infrastructure (AMI) project. The 2006 AMI projected expenditures compares with approximately $2.2 million of AMI expenditures in 2005.

	2005	2004	2003
Cash (Used in) Investing Activities (000's)	**$(24,367)**	$(22,922)	$(21,939)

Cash Provided by (Used in) Financing Activities—Cash provided by financing activities was $0.5 million in 2005, principally reflecting financing proceeds from the issuance of $15.0 million of long-term notes and $1.0 million of Common Stock which were substantially offset by the payment of dividends amounting to $7.8 million and repayment of $7.0 million of short-term bank indebtedness.

FG&E consummated, through a private placement, the issuance and sale on December 21, 2005 of $15.0 million of unsecured long-term notes to institutional investors. The notes have a term of 25 years and a coupon rate of 5.90%.

Cash used in financing activities was $8.5 million in 2004. In 2004, cash sources from increasing short-term debt by $3.3 million were offset by cash uses of $3.3 million to repay long-term debt, resulting in no net increase in total debt outstanding. In addition, the Company paid $7.9 million in common and preferred dividends in 2004 and redeemed Preferred Stock for $0.9 million.

Cash provided by financing activities in 2003 was $2.9 million, reflecting financing proceeds of $27.7 million from the issuance of common stock equity and new long-term debt, which was partially offset by the repayment of short-term borrowings of $13.6 million and long-term debt sinking fund payments of $3.2 million.

On October 29, 2003, the Company raised approximately $16.9 million (after deducting underwriting discounts and commissions and the expenses of the offering) through the sale of 717,600 shares of its common stock at a price of $25.40 per share in a registered public offering. The offering was increased from an original 520,000 shares to reflect a 20% upsizing of the transaction (104,000 shares) and the exercise of a 15% underwriters' over-allotment (93,600 shares).

On October 28, 2003, FG&E completed a $10 million private placement of long-term unsecured notes with a major insurance company. The notes have a term of 22 years and a coupon rate of 6.79%.

	2005	2004	2003
Cash Provided by (Used in) Financing Activities (000's)	**$466**	$(8,460)	$2,924

Dividends

Unitil's annualized common dividend was $1.38 per common share in 2005, 2004 and 2003. Unitil's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Interest Rate Risk

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 3.8%, 1.9% and 1.8% during 2005, 2004 and 2003, respectively.

Market Risk

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Regulatory Matters

Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil's utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the MDTE, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party vendors. Most customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next five to seven years, is $154 million as of December 31, 2005 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E—Electric Division—FG&E's primary business is providing electric distribution service under rates approved by the MDTE in 2002. FG&E had been required to purchase and provide power, as the provider of last resort, through either Standard Offer Service (Standard Offer) or Default Service, for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. The seven year term of Standard Offer, which included a requirement to provide service at rate levels which reflected state-mandated rate reductions, expired on February 28, 2005. FG&E continues to be required to be the supplier of last resort for its customers, however, and on March 1, 2005, customers previously on Standard Offer were automatically placed on Default Service. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of December 31, 2005, competitive suppliers were serving approximately 35 percent of FG&E's electric load.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $38.0 million at December 31, 2005, and $35.0

million at December 31, 2004, and is expected to be recovered in FG&E's rates over the next five to seven years. In addition, as of December 31, 2005, FG&E had recorded on its balance sheets $57.9 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates. See Note 1.

In May, 2005, the MDTE approved a Settlement Agreement among FG&E, the Massachusetts Office of the Attorney General (Attorney General), and representatives of industrial and low-income customers, in regards to future recovery of the deferred and unrecovered amounts described above. The Settlement Agreement provides for a rate path to allow recovery of FG&E's deferred stranded costs.

In March 2003, the MDTE opened an investigation into whether FG&E is in compliance with relevant statutes and regulations pertaining to transactions with affiliated companies and the MDTE's requirements for the pricing and procurement of Default Service. FG&E has asserted that the transaction in question with Enermetrix was not an affiliate transaction and resulted in net benefits to FG&E's customers. Hearing and briefing of the case were completed in 2003 and an MDTE decision is pending. Management believes the outcome of this matter will not have a material adverse effect on the financial position of the Company.

On December 1, 2005, FG&E filed its annual reconciliation and rate filing with the MDTE under its restructuring plan, seeking revised rates for transmission charges, transition charges, and default service adjustment. The revised rates were approved to go into effect January 1, 2006, subject to further investigation. FG&E made similar filings in 2002, 2003, and 2004, which were also approved subject to further investigation. On May 19, 2005, the MDTE, after investigation, issued an order approving FG&E's 2002 filing. Final review of FG&E's 2003 and 2004 filings, and FG&E's 2005 filing which is subject to investigation, are pending. Management believes that these filings will be approved without material change or adjustment.

FG&E—Gas Division—FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE in 2002. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal Cost of Gas Adjustment Clause (CGAC) and recovers other related costs through a reconciling Local Distribution Adjustment Clause. FG&E filed, and received MDTE approval of rate changes for reconciling clauses effective January 1, 2005, May 1, 2005, October 1, 2005 and November 1, 2005.

In 2001, the MDTE required the mandatory assignment of local distribution company's (LDC's) pipeline capacity to competitive marketers selling gas to FG&E's customers, thus protecting FG&E from exposure to costs for stranded capacity. In January 2004, the MDTE opened an investigation on whether the mandatory assignment of pipeline capacity should be continued. On June 6, 2005, the MDTE issued its order ruling that mandatory capacity assignment shall continue.

FG&E—Other—On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism to provide for the recovery of costs associated with the Company's employee pension benefits and Post Retirement Benefits Other than Pension (PBOP) expenses. FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism provides for an annual filing and rate adjustment with the MDTE. As of December 31, 2005, FG&E has recorded a regulatory asset of $2.5 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets. FG&E filed, and received MDTE approval of, revised pension/PBOP adjustment factors (PAFs) effective November 1, 2005 for its gas division and January 1, 2006 for its electric division.

On November 30, 2005, the MDTE announced a change in its method for recovery of gas cost-related bad debt, and determined that it would allow for full recovery of these costs on a reconciling basis. On December 15, 2005, FG&E filed a revised CGAC tariff reflecting this change which was approved effective January 1, 2006. FG&E also requested approval to recover its under-recovered gas cost-related bad debt for 2005 of approximately $164 thousand. A decision on this request is expected in 2006.

UES—UES provides electric distribution service to its customers pursuant to rates established under a 2002 restructuring settlement. On May 1, 2004, these distribution rates were increased by $1.0 million to provide for the recovery of PBOP costs. As the provider of last resort, UES also provides its customers with electric power through either Transition or Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES recovers its costs for this service through reconciling rate mechanisms.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery and Transition and Default Service, including certain charges that are subject to annual or periodic reconciliation or future review. As of December 31, 2005, UES had recorded on its balance sheets $57.0 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately five years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

The NHPUC approved UES' second annual reconciliation and rate filing under its restructuring plan effective May 1, 2005, including revised rates for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge.

On December 11, 2004, UES filed with the NHPUC a Petition for an accounting order to defer certain pension costs above those included in its base rates, until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007 (also see Note 8 below). On April 7, 2005, the NHPUC issued an order denying UES' Petition for an accounting order. In its analysis denying UES' request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that a full examination of UES' income and expenses would be undertaken when UES files a rate case. As of December 31, 2005, UES has recorded deferred pension costs of $1.0 million.

On November 4, 2005, UES filed a request for a base rate increase of $4.65 million. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving this request. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding.

On January 7, 2005, the NHPUC approved UES' petition for a one year extension of Transition Service and Default Service for rate class G1, and the associated solicitation process whereby UES intends to secure energy supplies for such extended service. As a result, UES' Transition Service supply obligation for all rate classes will end at the same time on April 30, 2006. The Company recovers the costs of Transition Service and Default Service in its rates at cost on a pass-through basis and therefore changes in these expenses do not affect earnings.

On April 1, 2005, UES filed a petition with the NHPUC for approval of a plan for procurement of Default Service power supply for service, commencing on May 1, 2006 for all rate classes. A settlement supporting the plan between UES, the Office of Consumer Advocate and the NHPUC Staff, was approved by the NHPUC on

September 9, 2005. Under the approved plan, UES will procure Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis.

Under the 2002 restructuring plan approved by the NHPUC, Unitil Power sold the entitlements to its long-term power supply portfolio to Mirant and UES purchased supplies for Transition and Default Service from Mirant for up to three years. Following the Chapter 11 bankruptcy filing by Mirant in July, 2003, Mirant agreed to continue to perform all obligations under its contracts with Unitil Power and UES pursuant to a settlement approved by the bankruptcy court in December 2003. As a result of the Mirant bankruptcy, UES and Unitil Power also pursued claims with Mirant with regards to a potential future default. In January 2005, UES, Unitil Power and Mirant filed a settlement with the bankruptcy court under which Mirant has agreed to put in place a replacement guarantee, or comparable security, to guarantee performance of its responsibilities under the agreement beginning May 2006. That settlement was approved by the bankruptcy court on January 18, 2005. On January 3, 2006, Mirant emerged from Chapter 11.

FERC—Wholesale Power Market Restructuring—FG&E, UES and Unitil Power are members of the NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the OATT, to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations, and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric supply marketplace. The regional bulk power system is operated by an independent corporate entity, the ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a RTO was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO in orders issued March 24, 2004 and November 3, 2004 to begin operation of the RTO structure effective February 1, 2005. As a result of the formation of the RTO, companies seeking transmission service throughout New England will be able to obtain that service under common terms, with much of their focus on dealing with ISO-NE, in cooperation with the local transmission providers. Several parties have appealed various issues associated with the FERC's approval of the RTO to Federal District Court of Appeals. Those proceedings are ongoing.

On March 1, 2004, ISO-NE filed a proposal to implement LICAP in New England to allow for the imposition of incentive pricing for transmission constrained areas. Both UES and FG&E are located in a non-constrained area of the power pool which should have modest LICAP prices for several years under the filed proposal. UES and FG&E have intervened in the proceeding. On October 21, 2005 the FERC issued an order directing that Settlement discussions take place and indicating that implementation of LICAP, if it proceeds, will not be earlier than October 1, 2006. This case continues to be contested at the FERC.

The formation of an RTO, LICAP and other wholesale market changes, including changes to transmission rates, is not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy costs approved by the MDTE and NHPUC. It is possible, however, that retail rates will be significantly increased over the next several years if LICAP is implemented consistent with the Initial Decision.

FERC—Other—In August 2003, Northeast Utilities (NU) filed with FERC to revise its comprehensive network service transmission rates to establish and implement a formula based rate, replacing a fixed rate tariff. A settlement among certain parties was approved by the FERC in September 2004, which reduced the allowed return on equity in the formula rates and resulted in refunds to the tariff customers, including UES.

On March 30, 2005, NU filed an executed Distribution Service Agreement (DSA) settlement between UES and NU with the FERC for effect on June 1, 2005. The DSA provides for cost recovery by NU for facilities used by UES that had been reclassified from transmission plant to distribution plant. On April 20, 2005 UES intervened in support of the DSA. Costs to UES under the DSA are estimated to be approximately $2 million annually. These costs are expected to be recovered through reconciling cost recovery mechanisms. On May 19, 2005 the FERC accepted NU's DSA filing and the rates went into effect on June 1, 2005.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of December 31, 2005, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan (MCP) that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed. During 2005, FG&E continued developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

On May 13, 2004 FG&E discovered an unauthorized excavation by another property owner on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated onto property owned by FG&E. FG&E promptly reported this discovery to the DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. The Completion Report for this release was submitted May 9, 2005.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1822 through 1978. In addition, any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Critical Accounting Policies

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment; the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet. The Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated

Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71.” In management’s opinion, the Company’s regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition—Regulated utility revenues are based on rates approved by state and federal regulatory commissions. These regulated rates are applied to customers’ accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts—The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company’s experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Pension and Postretirement Benefit Obligations—The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with FASB Statement No. 87, “Employers’ Accounting for Pensions” and FASB Statement No. 106, “Employers’ Accounting for Postretirement Benefits other than Pensions.” In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions.

The Company’s reported costs of providing pension and PBOP benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company’s health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and PBOP costs (collectively “postretirement costs”) are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company’s consolidated financial statements. See Note 8.

Pension expense is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company’s expected long-term rate of return on

Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

The discount rate that is utilized in determining future pension obligations is based on long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2005, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Pension Cost. Similarly, for 2004 and 2003, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 and $150,000, respectively. The compensation cost increase assumptions used for 2005, 2004 and 2003 were 3.50%, 3.50% and 4.00%, respectively, based on the expected long-term increase in compensation costs for personnel covered by the Plan.

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under FASB Statement No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts. See Note 7.

Depreciation—Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5). SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2005, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements' in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 7, "Income Taxes," Note 4, "Energy Supply," Note 8, "Benefit Plans," and Note 5, "Commitment and Contingencies," to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Reference is made to Item 1A. "Risk Factors" and the "Interest Rate Risk" and "Market Risk" sections of Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheet and consolidated statement of capitalization of Unitil Corporation and subsidiaries as of December 31, 2005, and the related consolidated statements of earnings, cash flows and changes in common stock equity for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Unitil Corporation and subsidiaries as of December 31, 2005 and the consolidated results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ Vitale, Caturano & Co. Ltd.

Boston, Massachusetts
February 3, 2006

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Unitil Corporation and subsidiaries as of December 31, 2004, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the two years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Unitil Corporation and subsidiaries as of December 31, 2004, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Unitil Corporation's internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2005 (not separately included herein), expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Boston, Massachusetts
February 17, 2005

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that Unitil Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission* (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Unitil Corporation and subsidiaries maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control-Integrated Framework* issued by the COSO. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in the *Internal Control-Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and consolidated statements of capitalization of Unitil Corporation and subsidiaries as of December 31, 2005, and the related consolidated statements of earnings, cash flows and changes in common stock equity for the year then ended, and our report dated February 3, 2006, expressed an unqualified opinion on those consolidated financial statements.

/s/ Vitale, Caturano & Co. Ltd.

Boston, Massachusetts
February 3, 2006

CONSOLIDATED STATEMENTS OF EARNINGS

(000's, except common shares and per share data)

Year Ended December 31,	**2005**	**2004**	**2003**
Operating Revenues:			
Electric	**$ 197,338**	$ 183,889	$ 190,864
Gas	**32,768**	28,685	28,612
Other	**2,039**	1,563	1,178
Total Operating Revenues	**232,145**	214,137	220,654
Operating Expenses:			
Purchased Electricity	**138,134**	125,940	134,036
Purchased Gas	**21,225**	17,486	17,421
Operation and Maintenance	**24,514**	23,297	22,706
Conservation & Load Management	**4,115**	4,003	3,930
Depreciation and Amortization	**19,123**	18,830	18,756
Provisions for Taxes:			
Local Property and Other	**5,218**	5,182	4,805
Federal and State Income	**4,275**	4,206	3,551
Total Operating Expenses	**216,604**	198,944	205,205
Operating Income	**15,541**	15,193	15,449
Other Non-Operating Expenses (Income)	**147**	193	(40)
Income Before Interest Expense	**15,394**	15,000	15,489
Interest Expense, net	**6,841**	6,774	7,531
Net Income	**8,553**	8,226	7,958
Less Dividends on Preferred Stock	**156**	215	236
Earnings Applicable to Common Shareholders	**$ 8,397**	$ 8,011	$ 7,722
Average Common Shares Outstanding—Basic	**5,551,420**	5,509,321	4,877,933
Average Common Shares Outstanding—Diluted	**5,567,718**	5,524,835	4,896,329
Earnings per Common Share—Basic and Diluted	**$ 1.51**	$ 1.45	$ 1.58

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS *(000's)*

ASSETS

December 31,	2005	2004
Utility Plant:		
Electric	**$234,153**	$222,121
Gas	**58,675**	53,208
Common	**26,515**	28,271
Construction Work in Progress	**5,624**	4,454
Utility Plant	**324,967**	308,054
Less: Accumulated Depreciation	**111,646**	104,051
Net Utility Plant	**213,321**	204,003
Current Assets:		
Cash	**3,207**	3,032
Accounts Receivable—(Net of Allowance for Doubtful Accounts of $470 and $501)	**23,631**	18,119
Accrued Revenue	**8,905**	9,754
Refundable Taxes	**351**	977
Material and Supplies	**3,675**	3,080
Prepayments and Other	**1,612**	1,771
Total Current Assets	**41,381**	36,733
Noncurrent Assets:		
Regulatory Assets	**179,719**	199,608
Prepaid Pension	**11,099**	10,990
Debt Issuance Costs, net	**2,343**	2,265
Other Noncurrent Assets	**2,218**	3,411
Total Noncurrent Assets	**195,379**	216,274
TOTAL	**$450,081**	$457,010

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (cont.) (000's)

CAPITALIZATION AND LIABILITIES

December 31,	2005	2004
Capitalization:		
Common Stock Equity	**$ 96,283**	$ 94,291
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225
Preferred Stock, Redeemable, Cumulative	**2,102**	2,113
Long-Term Debt, Less Current Portion	**125,365**	110,675
Total Capitalization	**223,975**	207,304
Current Liabilities:		
Long-Term Debt, Current Portion	**308**	285
Capitalized Leases, Current Portion	**261**	413
Accounts Payable	**20,600**	16,249
Short-Term Debt	**18,700**	25,675
Dividends Declared and Payable	**50**	50
Refundable Customer Deposits	**2,031**	1,545
Interest Payable	**1,353**	1,328
Other Current Liabilities	**2,677**	5,607
Total Current Liabilities	**45,980**	51,152
Deferred Income Taxes	**52,297**	56,156
Noncurrent Liabilities:		
Power Supply Contract Obligations	**114,906**	140,448
Capitalized Leases, Less Current Portion	**324**	183
Other Noncurrent Liabilities	**12,599**	1,767
Total Noncurrent Liabilities	**127,829**	142,398
TOTAL	**$450,081**	$457,010

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(000's except number of shares and par value)

December 31,	2005	2004
Common Stock Equity		
Common Stock, No Par Value (Authorized—8,000,000 shares; Outstanding—5,595,523 and 5,546,620 shares)	**$ 60,826**	$ 59,795
Stock Compensation Plans	**1,310**	1,059
Retained Earnings	**34,147**	33,437
Total Common Stock Equity	**96,283**	94,291
Preferred Stock		
UES Preferred Stock, Non-Redeemable, Non-Cumulative:		
6.00% Series, $100 Par Value	**225**	225
FG&E Preferred Stock, Redeemable, Cumulative:		
5.125% Series, $100 Par Value	**892**	899
8.00% Series, $100 Par Value	**1,210**	1,214
Total Preferred Stock	**2,327**	2,338
Long-Term Debt		
UES First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15,000**	15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000
FG&E Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19,000**	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000
6.79% Notes, Due October 15, 2025	**10,000**	10,000
5.90% Notes, Due December 15, 2030	**15,000**	—
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**5,673**	5,960
Total Long-Term Debt	**125,673**	110,960
Less: Long-Term Debt, Current Portion	**308**	285
Total Long-Term Debt, Less Current Portion	**125,365**	110,675
Total Capitalization	**$223,975**	$207,304

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS *(000's)*

Year Ended December 31,	2005	2004	2003
Operating Activities:			
Net Income	**$ 8,553**	$ 8,226	$ 7,958
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**19,123**	18,830	18,756
Deferred Tax (Benefit) Provision	**(240)**	3,166	6,375
Changes in Current Assets and Liabilities:			
Accounts Receivable	**(5,512)**	(658)	2,052
Accrued Revenue	**849**	275	(6,795)
Refundable Taxes	**626**	2,839	1,035
Materials and Supplies	**(595)**	(219)	(538)
Prepayments and Other	**159**	4,375	(4,411)
Accounts Payable	**4,351**	1,225	803
Refundable Customer Deposits	**486**	116	93
Interest Payable	**25**	(28)	45
Other Current Liabilities	**1,311**	1,353	(4,808)
Deferred Restructuring and Other Charges	**(6,256)**	(5,900)	(6,058)
Other, net	**1,196**	(2,952)	1,114
Cash Provided by Operating Activities	**24,076**	30,648	15,621
Investing Activities:			
Property, Plant and Equipment Additions	**(24,367)**	(22,922)	(21,939)
Cash Used In Investing Activities	**(24,367)**	(22,922)	(21,939)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**(6,975)**	3,265	(13,580)
Issuance of Long-Term Debt	**15,000**	—	10,000
Repayment of Long-Term Debt	**(286)**	(3,264)	(3,244)
Retirement of Preferred Stock	**(11)**	(931)	(53)
Dividends Paid	**(7,843)**	(7,857)	(7,056)
Issuance of Common Stock	**1,031**	947	17,628
Repayment of Capital Lease Obligations	**(450)**	(620)	(771)
Cash Provided by (Used In) Financing Activities	**466**	(8,460)	2,924
Net Increase (Decrease) in Cash	**175**	(734)	(3,394)
Cash at Beginning of Year	**3,032**	3,766	7,160
Cash at End of Year	**$ 3,207**	$ 3,032	$ 3,766
Supplemental Information:			
Interest Paid	**$ 9,455**	$ 9,052	$ 9,113
Income Taxes Paid (Refunded)	**$ 4,544**	$ 990	$ (2,541)
Supplemental Schedule of Noncash Activities:			
Capital Leases Incurred	**$ 439**	$ 246	$ 109

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(000's except number of shares)

	Common Shares	Stock Compensation Plans	Retained Earnings	Total
Balance at January 1, 2003	$41,220	$ 990	$32,140	**$74,350**
Net Income for 2003			7,958	**7,958**
Dividends on Preferred Shares			(236)	**(236)**
Dividends on Common Shares			(6,813)	**(6,813)**
Stock Compensation Plans		(82)		**(82)**
Common Stock Offering—717,600 Shares	16,911			**16,911**
Issuance of 28,714 Common Shares	717			**717**
Balance at December 31, 2003	58,848	908	33,049	**92,805**
Net Income for 2004			8,226	**8,226**
Dividends on Preferred Shares			(215)	**(215)**
Dividends on Common Shares			(7,623)	**(7,623)**
Stock Compensation Plans		151		**151**
Issuance of 35,310 Common Shares	947			**947**
Balance at December 31, 2004	59,795	1,059	33,437	**94,291**
Net Income for 2005			8,553	**8,553**
Dividends on Preferred Shares			(156)	**(156)**
Dividends on Common Shares			(7,687)	**(7,687)**
Stock Compensation Plans		251		**251**
Issuance of 38,003 Common Shares	1,031			**1,031**
Balance at December 31, 2005	**$60,826**	**$1,310**	**$34,147**	**$96,283**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES) (formed in 2002 by the combination and merger of Unitil's former utility subsidiaries Concord Electric Company and Exeter & Hampton Electric Company), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—In accordance with current accounting pronouncements, the Company's consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas in the Company-owned retail distribution utilities: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the Massachusetts Department of Telecommunications and Energy (MDTE) and UES is regulated by the New Hampshire Public Utilities Commission (NHPUC). Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided below. The Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

	December 31,	
Regulatory Assets consist of the following (000's)	**2005**	**2004**
Power Supply Buyout Obligations	**$114,906**	$140,448
Income Taxes	**17,546**	20,670
Recoverable Deferred Restructuring Charges	**35,826**	30,840
Recoverable Generation-related Assets	**3,316**	5,169
Pension / Post-retirement Benefits Other than Pension	**8,125**	2,481
Total Regulatory Assets	**$179,719**	$199,608

Massachusetts and New Hampshire have both passed utility industry restructuring legislation and the Company has filed and implemented its restructuring plans in both states. The Company is allowed to recover certain types of costs through ongoing assessments to be included in future regulated service rates. Based on the recovery mechanism that allows recovery of all of its stranded costs and deferred costs related to restructuring, the Company has recorded regulatory assets that it expects to fully recover in future periods. The Company expects to continue to meet the criteria for the application of SFAS No. 71 for the distribution portion of its assets and operations for the foreseeable future. If a change in accounting for regulatory assets under SFAS No. 71 were to occur to the distribution portion of the Company's operations, it could have a material adverse effect on the Company's earnings and retained earnings in that year and could have a material adverse effect on the Company's ongoing financial condition as well.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In management's opinion, the Company's regulated subsidiaries will be subject to SFAS No. 71 for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. Financial instruments that subject the Company to credit risk concentrations consist of cash and cash equivalents and accounts receivable. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. The Company believes it is not exposed to any significant credit risk on cash.

Goodwill and Intangible Assets—The Company does not have any goodwill recorded on its balance sheet as of December 31, 2005. There are no significant intangible assets recorded by the Company at December 31, 2005. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

Off-Balance Sheet Arrangements—As of December 31, 2005, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases and, in management's opinion, the amount of these transactions is not material.

Investments and Trading Activities—During the year, the Company does invest in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for book accounting purposes.

Derivatives—The Company enters into wholesale electric and gas energy supply contracts to serve its customers. The Company's policy is to review each contract and determine whether they meet the criteria for classification as derivatives under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133) and / or FASB Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). As of December 31, 2005, the Company determined that none of its wholesale electric and gas energy supply contracts met the criteria for classification as a derivative instrument. Additionally, the Company may enter into interest rate hedging transactions with respect to existing indebtedness and anticipated debt offerings. As of December 31, 2005, the Company has not entered into any such transactions. However, should the Company enter into any such transactions in the future, its policy will be to review each transaction and determine whether it meets the criteria for classification as derivatives under SFAS No. 133 and / or SFAS No. 149.

Utility Revenue Recognition—Regulated utility revenues are based on rates approved by federal and state regulatory commissions. These regulated rates are applied to customers' accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition—Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts—The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for

Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Pension and Postretirement Benefit Obligations—The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with FASB Statement No. 87, "Employers' Accounting for Pensions" (SFAS No. 87) and FASB Statement No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" (SFAS No. 106). In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions.

The Company's reported costs of providing pension and PBOP benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and PBOP costs (collectively "postretirement costs") are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements. See Note 8.

Pension income is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets of 8.50%, 8.75% and 8.75% for 2005, 2004 and 2003, respectively. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2005. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2005, 2004 and 2003 was $2,391,745, $1,981,667 and $1,106,827, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2005, 2004 and 2003 would have been $2,225,181, $2,119,667 and $2,332,699 respectively.

The discount rate that is utilized in determining future pension obligations is based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the period January 1, 2005 through May 31, 2005, the discount rate used was 6.50%. In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the defined benefit pension plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%. The discount rates used for the 2004 and 2003 fiscal years were 6.50% and 7.00%, respectively. For 2005, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Pension Cost. Similarly, for 2004 and 2003, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 and $150,000, respectively. The compensation cost increase assumptions used for 2005, 2004 and 2003 were 3.50%, 3.50% and 4.00%, respectively, based on the expected long-term increase in compensation costs for personnel covered by the Plan.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company policy is to record those estimates in accordance with the American Institute of Certified Public Accountants Statement of Position 94-6, "Disclosure of Certain Significant Risks and Uncertainties."

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5). SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2005, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below. See Note 5.

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 2.33%, 1.64% and 2.14% in 2005, 2004 and 2003, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company does not account separately for negative salvage, or cost of retirement obligations as defined in FASB Statement No. 143, "Accounting for Asset Retirement Obligations" and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations." The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At December 31, 2005 and December 31, 2004, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $13.4 million and $12.7 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets.

Depreciation provisions for Unitil's utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2005 – 4.69%, 2004 – 4.70% and 2003 – 4.73%.

Amortization provisions include the recovery of a portion of FG&E's former investment in Seabrook Station, a nuclear generating unit, in rates to its customers through the Seabrook Amortization Surcharge as ordered by the

MDTE. FG&E's asset related to Seabrook Station became fully-amortized in the third quarter of 2005. In addition, FG&E is amortizing the balance of its unrecovered electric generating related assets, which are recorded as Regulatory Assets, in accordance with its electric restructuring plan approved by the MDTE. See Note 5.

Environmental Matters—The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. In the past three years, the Company has performed work on two environmental remediation projects, the Sawyer Passway MGP Site and the Former Electric Generating Station. The Company has or will recover substantially all of the cost of the work performed to date from customers or from its insurance carriers. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of December 31, 2005, there are no material losses that would require additional liability reserves to be recorded. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation currently using the fair value-based method. See Note 2.

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109). The Company does not currently have any valuation allowances against its recorded deferred tax amounts. See Note 7.

Dividends—The Company is currently paying a dividend at an annual rate of $1.38 per common share.

The Company's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Recently Issued Pronouncements—In May 2005, the FASB issued FASB Statement No. 154, "Accounting Changes and Error Corrections", (SFAS No. 154), which replaces Accounting Principles Board Opinion No. 20, "Accounting Changes" and FASB Statement No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to do so. SFAS No. 154 also provides that (1) a change in the method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) correction of errors in previously issued financial statements should be termed a "restatement." The new standard is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. The Company has adopted SFAS No. 154 and determined that it does not expect that it will have an impact on the Company's Consolidated Financial Statements.

In December 2004, the FASB issued revised Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R), effective as of the beginning of the first annual reporting period that begins after June 15, 2005. SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. The Company uses the fair value method for share-based payment awards and therefore the provisions of SFAS No. 123(R) will have no impact on the Consolidated Financial Statements.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS No. 106-1) and Statement No. 106-2 (SFAS No. 106-2), "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary's annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS No. 106-1 and SFAS No. 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation and how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods. On January 28, 2005, the final Medicare Part D Prescription Drug Rules were posted to the Federal Register. Based on these rules, the Company's estimated PBOP Projected Benefit Obligation was reduced by $5.1 million. Also, the Company has estimated that its annual PBOP costs will be reduced by $0.4 million under the Act. These reductions are reflected in the Company's Consolidated Financial Statements. The Company's health care insurance provider has concluded that the Company's PBOP Plan is equal to or better than standard Medicare Part D coverage. Additionally, the Company's recognition of the Act is not expected to have any impact on the rate of participation in the PBOP Plan or per capita claims.

In December 2003, the FASB issued Statement No. 132(R) (SFAS 132(R)), a revision of its original Statement No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS 132). SFAS 132(R) revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by SFAS No. 87, FASB Statement No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" and SFAS No. 106". SFAS 132(R) retains the disclosure requirements contained in SFAS 132 and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. The Company adopted this statement in 2003.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46) and in December 2003 issued a revised FIN 46. This interpretation clarified the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," and replaced the current accounting guidance relating to the consolidation of variable interest entities (VIE's) established on the basis of contractual, ownership or other monetary interests. The Company reviewed its investments and affiliations and determined that it had a variable interest in the Unitil Retiree Trust (URT), a special purpose entity established January 1993. URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. URT was under the direction of an independent Board of Trustees whose voting members were comprised of former employees of the Company, elected by and from the membership of URT. In the fourth quarter of 2003, URT was dissolved by a vote of its trustees and the Company assumed the obligations of URT as of October 1, 2003. There are no other entities identified by the Company that qualify as VIE's under FIN 46. See Note 8 for additional discussion regarding FIN 46 and the Company's accounting for Postretirement Benefits other than Pensions.

In December 2002, the FASB issued Statement No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure." (SFAS No. 148). SFAS No. 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation" to provide alternative methods of transition for a voluntary change to the fair value-based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method on reported results. The Company recognizes compensation cost at fair value at the date of grant. The Company has already adopted the provisions of SFAS No. 148 and therefore there is no impact on the Consolidated Financial Statements.

Note 2: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

Public Offering 2003—On October 29, 2003, the Company raised approximately $16.9 million (after deducting underwriting discounts and commissions and the estimated expenses of the offering) through the sale of 717,600 shares of its common stock at a price of $25.40 per share in a registered public offering. The offering was increased from an original 520,000 shares to reflect a 20% upsizing of the transaction (104,000 shares) and the exercise of a 15% underwriters' over-allotment (93,600 shares). The Company used the proceeds from this offering to make capital contributions of $6 million to UES and $6 million to FG&E and for other general corporate purposes.

Dividend Reinvestment and Stock Purchase Plan—During 2005, the Company sold 38,003 shares of its Common Stock, at an average price of $27.15 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $1,031,786 were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's Common Stock and cash payments in additional shares of the Company's Common Stock. During 2004 and 2003, the Company raised $946,883 and $716,936, respectively, of additional common equity through the issuance of 35,310 and 28,714 shares, respectively, of its Common Stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired—During 2005, 2004 and 2003, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. Details of the plans are as follows:

Restricted Stock Plan—On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company Common Stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided in the Plan. Awards fully vest over a period of four years at a rate of 25% each year. During the vesting period, dividends on restricted shares underlying the Award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the Award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit. On March 8, 2005, 10,900 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $299,423. On April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $293,715. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period and was $265,900 in 2005, including amounts for tax gross-up.

Unitil Corporation Key Employee Stock Option Plan—The "Unitil Corporation Key Employee Stock Option Plan" was a 10-year plan which began in March 1989. The number of shares underlying options granted under this plan, as well as the terms and conditions of each grant, were determined by the Key Employee Stock Option Plan Committee of the Board of Directors, subject to plan limitations. At December 31, 2005, 29,101 shares underlying options had been approved and were available for future issuance as dividend equivalents earned under the plan. All options granted under this plan vested upon grant. The 10-year period in which options could be granted under this plan expired in March 1999. The expiration date of the remaining outstanding options is November 3, 2007. The plan provides dividend equivalents on options granted, which are recorded at fair value as compensation expense. The total compensation expenses recorded by the Company with respect to this plan were $51,000, $49,000 and $46,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

Share Option Activity of the "Unitil Corporation Key Employee Stock Option Plan" is presented in the following table:

	2005	2004	2003
Beginning Options Outstanding and Exercisable	**25,000**	25,000	25,000
Dividend Equivalents Earned—Prior Years	**11,321**	9,495	7,645
Dividend Equivalents Earned—Current Year	**1,881**	1,826	1,850
Options Exercised	**—**	—	—
Ending Options Outstanding and Exercisable	**38,202**	36,321	34,495
Weighted Average Exercise Price per Share	**$11.89**	$12.51	$13.17
Range of Option Exercise Price per Share	**$12.11-$18.28**	$12.11-$18.28	$12.11-$18.28
Weighted Average Remaining Contractual Life	**1.9 years**	2.9 years	3.9 years

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's Common Stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. There was no compensation expense associated with this plan in 2005 and 2004. The total compensation expense recorded by the Company with respect to this plan was ($178,000) for the year ended December 31, 2003, reflecting a reversal of prior compensation expense due to stock option forfeitures. This plan was terminated on January 16, 2003. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of options will be made under this plan.

	2005		2004		2003	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Beginning Options Outstanding	**107,000**	**$27.13**	107,000	$27.13	172,500	$26.99
Options Granted	**—**	**—**	—	—	—	—
Options Forfeited	**—**	**—**	—	—	(65,500)	$26.77
Ending Options Outstanding	**107,000**	**$27.13**	107,000	$27.13	107,000	$27.13
Options Vested and Exercisable-end of year	**107,000**	**$27.13**	107,000	$27.13	107,000	$27.13

The Company has adopted SFAS No. 123, "Accounting for Stock Based Compensation," and recognizes compensation costs at fair value at the date of grant.

The following summarizes certain data for options outstanding at December 31, 2005:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$20.00-$24.99	34,500	$23.38	3.2 years
$25.00-$29.99	37,500	$25.88	5.1 years
$30.00-$34.99	35,000	$32.17	4.1 years
	107,000		

There were no options granted during 2005, 2004 or 2003.

Restrictions on Retained Earnings—Unitil Corporation has no restriction on the payment of common dividends from retained earnings.

Its two retail distribution subsidiaries, UES and FG&E, do have restrictions. Under the terms of the First Mortgage Bond Indentures, UES had $13,300,000 available for the payment of cash dividends on its Common Stock at December 31, 2005. Under the terms of long-term debt purchase agreements, FG&E had $7,842,000 of retained earnings available for the payment of cash dividends on its Common Stock at December 31, 2005. Common dividends declared by UES and FG&E are paid exclusively to Unitil Corporation.

Preferred Stock

Unitil's two retail distribution companies, UES and FG&E, have preferred stock outstanding. At December 31, 2005, UES has a 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and FG&E has two series of Redeemable, Cumulative Preferred Stock outstanding, the 5.125% Series and the 8.00% Series.

FG&E is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, FG&E may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2005, 2004 and 2003 related to the annual redemption offer were $11,400, $26,900 and $53,400, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2005 is $117,000 per year.

On October 15, 2004, UES redeemed and retired the remaining three outstanding issues of its Redeemable, Cumulative Preferred Stock at par, aggregating $904,100. The three issues redeemed and retired were the 8.70% Series (aggregate par value of $215,000), the 8.75% Series (aggregate par value of $313,600) and the 8.25% Series (aggregate par value of $375,500). UES used operating cash to effect this transaction.

Note 3: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowing arrangements. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Substantially all the property of Unitil's New Hampshire utility operating subsidiary, UES, is subject to liens of indenture under which First Mortgage bonds have been issued. UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing

UES Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The UES agreements further require that if UES defaults on any UES FMB securities, it would constitute a default for all UES FMB securities. The UES default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

All of the long-term debt of Unitil’s Massachusetts utility operating subsidiary, FG&E, is issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of FG&E’s long-term debt ranks pari passu with its other senior unsecured long-term debt. The long-term debt’s negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the UES agreements, FG&E agreements require that if FG&E defaults on any FG&E long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets.

Total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $286,368, $3,264,421 and $3,244,156 in 2005, 2004 and 2003, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2005 is: 2006 – $308,082, 2007 – $335,877, 2008 – $363,755, 2009 – $393,946 and 2010 – $426,643.

FG&E, through a private placement, consummated the issuance and sale on December 21, 2005 of $15 million of unsecured long-term notes to institutional investors. The notes have a term of 25 years and a coupon rate of 5.90%. The net proceeds were used to reduce FG&E’s outstanding short-term indebtedness.

On October 28, 2003, FG&E completed a $10 million private placement of long-term unsecured notes with a major insurance company. The notes have a term of 22 years and a coupon rate of 6.79%. The net proceeds were used to replace short-term indebtedness.

The fair value of the Company’s long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company’s long-term debt at December 31, 2005 is estimated to be in a range of up to approximately $140 million, before considering any costs, including prepayment costs, to market the Company’s debt. Currently, management believes that there is no active market in the Company’s debt securities, which have all been sold through private placements.

The agreements under which the long-term debt of Unitil’s two principal subsidiaries, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations.

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and interest on regulatory liabilities. Interest income is mainly derived from carrying charges on restructuring related stranded costs and other deferred costs recorded as regulatory assets by the Company’s retail distribution utilities as approved by regulators in New

Hampshire and Massachusetts. Over the long run, as deferred costs are recovered through rates, the interest costs associated with these deferrals are expected to decrease together with a decrease in interest income. A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (000's)	2005	2004	2003
Interest Expense			
Long-term Debt	**$ 8,423**	$ 8,492	$ 8,170
Short-term Debt	**1,046**	629	1,071
Subtotal Interest Expense	**9,469**	9,121	9,241
Interest Income			
Regulatory Assets	**(2,525)**	(2,310)	(1,657)
AFUDC and Other	**(103)**	(37)	(53)
Subtotal Interest Income	**(2,628)**	(2,347)	(1,710)
Total Interest Expense, net	**$ 6,841**	$ 6,774	$ 7,531

Credit Arrangements

At December 31, 2005, Unitil had unsecured committed bank lines for short-term debt in the aggregate amount of $44.0 million with three banks for which it pays commitment fees. The weighted average interest rates on all short-term borrowings were 3.8%, 1.9% and 1.8% during 2005, 2004 and 2003, respectively. The Company had short-term debt outstanding through bank borrowings of approximately $18.7 million and $25.7 million at December 31, 2005 and December 31, 2004, respectively.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment. FG&E had a 22-year facility lease in which the primary term was scheduled to end on January 31, 2003. On February 1, 2003, a 10-year extended term commenced extending the lease term through January 31, 2013. Furthermore, the amended lease agreement allows for three additional five-year renewal periods at the option of FG&E. This lease, as well as other leases for equipment used by Unitil's subsidiaries, is recorded as an operating lease. In prior years, this lease was classified as a capital lease. The change in classification was the result of the renegotiation of the lease terms described above.

The following is a schedule of the leased property under capital leases by major classes:

Classes of Utility Plant (000's)	Asset Balances at December 31, 2005	2004
Common Plant	**$985**	$2,769
Less: Accumulated Depreciation	**400**	2,197
Net Plant	**$585**	$ 572

The following is a schedule of future minimum lease payments and present value of net minimum lease payments under capital leases, as of December 31, 2005:

Year Ending December 31 (000's)	
2006	$291
2007	203
2008	139
2009	9
2010	2
2011-2015	1
Total Minimum Lease Payments	$645
Less: Amount Representing Interest	60
Present Value of Net Minimum Lease Payments	$585

Total rental expense charged to operations for the years ended December 31, 2005, 2004 and 2003 amounted to $301,000, $249,000 and $294,000 respectively.

The following is a schedule of future operating lease payment obligations as of December 31, 2005:

Year Ending December 31 (000's)	
2006	$ 390
2007	390
2008	390
2009	387
2010	364
2011-2015	818
Total Future Operating Lease Payments	$2,739

Guarantees

The Company also provides limited guarantees on certain energy contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2005 there are $6.0 million of guarantees outstanding and these guarantees extend through October 24, 2007. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

Note 4: Energy Supply

Electricity Supply:

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from competitive retail suppliers, though most customers continue to purchase such supplies through the retail distribution utilities. The transition to retail choice required the divestiture of Unitil's existing power supply arrangements and the procurement of replacement supplies which provided the flexibility for migration of customers to and from utility service. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the Independent System Operator—New England (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

Wyman Unit No. IV—FG&E continues to have a 0.1822% non-operating ownership interest in the Wyman Unit No. IV (Wyman IV), an oil-fired electric generating station located in Yarmouth, Maine. The lead operating owner of Wyman IV is FPL Energy Wyman IV, LLC. In accordance with the electric industry restructuring in Massachusetts, and pursuant to the generation assets and power supply divestiture process discussed below, FG&E effectively divested its economic interest in Wyman IV when it entered into an agreement with Select Energy, Inc. to, among other things, sell its entire entitlement in the output from Wyman IV over the expected remaining operating life of the unit. Kilowatt-hour generation and operating expenses associated with Wyman IV are divided on the same basis as ownership. FG&E's proportionate ownership costs in Wyman IV are reflected in the Consolidated Statements of Earnings. Revenues from the entitlement sale of Wyman IV reflect a matching and collection of these costs. Accordingly, the cost associated with FG&E's ownership in Wyman IV does not have a material impact on earnings.

Information with respect to FG&E's ownership in Wyman Unit No. IV, at December 31, 2005, is shown below:

Joint Ownership Unit	State	Proportionate Ownership	Share of Total MW	Company's Net Book Value (000's)
Wyman Unit No. IV	ME	0.1822%	1.13	$40

Power Supply Divestiture

Prior to May 1, 2003, UES purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, UES and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to UES ceased and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement UES continues to pay contract release payments to Unitil Power for costs associated with the portfolio sale and its other ongoing, power supply-related costs. Recovery of the contract release payments by UES from its retail customers has been approved by the NHPUC.

Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant in 2003. The purchase of power to supply UES' Transition Service and Default Service requirements by UES from Mirant was linked to the Unitil Power divestiture. The NHPUC Order completed the state approval process for Unitil's restructuring plan under which UES implemented customer choice for its customers on May 1, 2003. The divested power supply contracts continue through October 2010.

In March 1999, FG&E completed the sale of its 4.5% interest in the New Haven Harbor Station generating unit. FG&E divested its remaining owned generation assets and long-term power supply contracts to Select Energy, Inc., a subsidiary of Northeast Utilities. Under the Select Energy contract, which was approved by the MDTE in January 2000, and went into effect February 1, 2000, FG&E began selling the entire output from its remaining long-term power supply contracts and the output of its two joint ownership units, Millstone Unit 3 and Wyman IV, to Select Energy. Upon the sale of FG&E's share of Millstone Unit 3 in 2001, this portion of the contract sale ceased. Effective with the termination of the Purchased Power Contract between FG&E and Linweave, Inc. on December 1, 2004, this portion of the contract sale also ceased. On December 30, 2005 Select Energy assigned the FG&E contracts portfolio to Constellation Energy Commodities Group (Constellation) effective January 1, 2006. Recovery of all costs associated with the divestiture of the FG&E power supply portfolio has been approved by the MDTE.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into wholesale electric power supply contracts with various wholesale suppliers. In particular, FG&E has entered into power supply contracts to meet its power supply obligations associated with the provision of Standard Offer Service (Standard Offer) and Default Service. Standard Offer was offered only to customers who had both taken service from FG&E since the inception of retail choice in 1998 and had not switched to a competitive retail supplier. Consistent with MDTE regulations, Standard Offer ended January 31, 2005. Effective February 1, 2005 FG&E customers are eligible for Default Service. FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service. MDTE policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, with each 12 month contract providing 50% of the class requirements.

The MDTE is investigating alternatives to the current procurement policy for all accounts, other than the large general accounts. This process could potentially lead to the procurement of FG&E Default Service power supply for longer duration in order to provide more price stability for smaller customers throughout Massachusetts for whom competitive retail options are relatively scarce.

UES has entered into a power supply contract to meet its power supply obligations associated with the provision of Transition Service and Default Service. Transition Service is available to any UES customer who has not chosen a competitive retail supplier. UES' Default Service is available to any customer who has chosen a competitive retail energy supplier and returns to retail energy supply from UES. UES has entered into a power supply contract for the provision of Transition Service and Default Service with Mirant. This power supply contract provides fixed unit prices for both Transition Service and Default Service for UES' largest general service accounts through April 2005 and for all other accounts through April 2006.

On July 14, 2003 Mirant filed for Chapter 11 Bankruptcy protection. Mirant is currently performing all of its contractual obligations to both Unitil Power and UES and has satisfied all of its pre-petition claims made by Unitil. On January 3, 2006 Mirant emerged from Chapter 11 Bankruptcy protection.

In January, 2005 the NHPUC approved two six-month supply contracts for Transition Service and Default Service for UES' large general service customers for the period May, 2005 through April, 2006. In September, 2005 the NHPUC approved a Settlement among UES, NHPUC Staff and the Office of Consumer Advocate which provides for UES to procure Default Service for its largest general service accounts through successive competitive solicitations of three-months duration and to procure Default Service for all other customers through a series of two one-year contracts and two three-year contracts with each contract covering 25% of the total requirements of the group. The first two contracts were of 6-months and 18-months duration in order to stagger the start dates of future 1-year and 3-year procurements. On November 2, 2005, the NHPUC approved those two initial Default Service contracts for service starting May 1, 2006.

Regional Transmission and Power Markets

FG&E, UES and Unitil Power are members of the NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the OATT, to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations, and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The regional bulk power system is operated by an independent corporate entity, ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a RTO was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO in orders issued March 24, 2004 and November 3, 2004 to begin operation of the RTO structure effective February 1, 2005. As a result of the formation of the RTO, companies seeking transmission service throughout New England will be able to obtain that service under common terms, with much of their focus on dealing with ISO-NE, in cooperation with the local transmission providers.

On March 1, 2004, ISO-NE filed a proposal to implement LICAP in New England to allow for the imposition of incentive pricing for transmission constrained areas. UES and FG&E have intervened in the proceeding. Both UES and FG&E are located in a non-constrained area of the power pool. On October 21, 2005 the FERC issued an order directing that Settlement discussions take place and indicating that implementation of LICAP, if it proceeds, will not be earlier than October 1, 2006. This case is still before the FERC.

The formation of an RTO, LICAP and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDTE and NHPUC.

Gas Supply:

FG&E's natural gas customers now have the opportunity to purchase their natural gas supply from third-party vendors, though most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E purchases natural gas from domestic and Canadian suppliers under contracts of one year or less, as well as from producers and marketers on the spot market and arranges for the transportation to its distribution facilities under firm long-term contracts with the Tennessee interstate pipeline. FG&E has a four-year contract for LNG supply which ends in 2008 which was approved by the MDTE. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2003 through 2005.

Sources of Gas Supply
(Expressed as percent of total MMBtu of gas purchased)

	2005	2004	2003
Natural Gas:			
Domestic firm	**84.8%**	85.0%	94.0%
Canadian firm	**3.4%**	5.4%	1.3%
Domestic spot market	**9.3%**	5.9%	1.3%
Total natural gas	**97.5%**	96.3%	96.6%
Supplemental gas	**2.5%**	3.7%	3.4%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2005	2004	2003
Cost of gas purchased and sold per MMBtu	**$10.83**	$8.42	$7.14
Percent Increase (Decrease) from prior year	**28.7%**	17.9%	43.9%

FG&E has available under firm contract 14,057 MMBtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a liquefied natural gas (LNG) storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Note 5: Commitments and Contingencies

Regulatory Matters

Overview—Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil's utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the MDTE, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party vendors. Most customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup on a pass-through basis, through reconciling rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next five to seven years, is $154 million as of December 31, 2005 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E—Electric Division—FG&E's primary business is providing electric distribution service under rates approved by the MDTE in 2002. FG&E had been required to purchase and provide power, as the provider of last resort, through either Standard Offer or Default Service, for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. The seven year term of Standard Offer, which included a requirement to provide service at rate levels which reflected state-mandated rate reductions, expired on February 28, 2005. FG&E continues to be required to be the supplier of last resort for its customers, however, and on March 1, 2005, customers previously on Standard Offer were automatically placed on Default Service. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of December 31, 2005, competitive suppliers were serving approximately 35 percent of FG&E's electric load.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $38.0 million at December 31, 2005, and $35.0

million at December 31, 2004, and is expected to be recovered in FG&E's rates over the next five to seven years. In addition, as of December 31, 2005, FG&E had recorded on its balance sheets $57.9 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates. See Note 1.

In May, 2005, the MDTE approved a Settlement Agreement among FG&E, the Massachusetts Office of the Attorney General (Attorney General), and representatives of industrial and low-income customers, in regards to future recovery of the deferred amounts described above. The Settlement Agreement provides for a rate path to allow recovery of FG&E's deferred stranded costs.

In March 2003, the MDTE opened an investigation into whether FG&E is in compliance with relevant statutes and regulations pertaining to transactions with affiliated companies and the MDTE's requirements for the pricing and procurement of Default Service. FG&E has asserted that the transaction in question with Enermetrix was not an affiliate transaction and resulted in net benefits to FG&E's customers. Hearing and briefing of the case were completed in 2003 and an MDTE decision is pending. Management believes the outcome of this matter will not have a material adverse effect on the financial position of the Company.

On December 1, 2005, FG&E filed its annual reconciliation and rate filing with the MDTE under its restructuring plan, seeking revised rates for transmission charges, transition charges, and default service adjustment. The revised rates were approved to go into effect January 1, 2006, subject to further investigation. FG&E made similar filings in 2002, 2003, and 2004, which were also approved subject to further investigation. On May 19, 2005, the MDTE, after investigation, issued an order approving FG&E's 2002 filing. Final review of FG&E's 2003 and 2004 filings, and FG&E's 2005 filing which is subject to investigation, are pending. Management believes that these filings will be approved without material changes or adjustments.

FG&E—Gas Division—FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE in 2002. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause. FG&E filed, and received MDTE approval of rate changes for reconciling clauses effective January 1, 2005, May 1, 2005, October 1, 2005 and November 1, 2005.

In 2001, the MDTE required the mandatory assignment of LDC's pipeline capacity to competitive marketers selling gas to FG&E's customers, thus protecting FG&E from exposure to costs for stranded capacity. In January 2004, the MDTE opened an investigation on whether the mandatory assignment of pipeline capacity should be continued. On June 6, 2005, the MDTE issued its order ruling that mandatory capacity assignment shall continue.

FG&E—Other—On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism to provide for the recovery of costs associated with the Company's employee pension benefits and PBOP expenses. FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism provides for an annual filing and rate adjustment with the MDTE. As of December 31, 2005, FG&E has recorded a regulatory asset of $2.5 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets. FG&E filed, and received MDTE approval of, revised pension/PBOP adjustment factors (PAFs) effective November 1, 2005 for its gas division and January 1, 2006 for its electric division.

On November 30, 2005, the MDTE announced a change in its method for recovery of gas cost-related bad debt, and determined that it would allow for full recovery of these costs on a reconciling basis. On December 15, 2005, FG&E filed a revised CGAC tariff reflecting this change which was approved effective January 1, 2006. FG&E also requested approval to recover its under-recovered gas cost-related bad debt for 2005 of approximately $164 thousand. A decision on this request is expected in 2006.

UES—UES provides electric distribution service to its customers pursuant to rates established under a 2002 restructuring settlement. On May 1, 2004, these distribution rates were increased by $1.0 million to provide for the recovery of PBOP costs. As the provider of last resort, UES also provides its customers with electric power through either Transition or Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery and Transition and Default Service, including certain charges that are subject to annual or periodic reconciliation or future review. As of December 31, 2005, UES had recorded on its balance sheets $57.0 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately five years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

The NHPUC approved UES' second annual reconciliation and rate filing under its restructuring plan effective May 1, 2005, including revised rates for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge.

On December 11, 2004, UES filed with the NHPUC a Petition for an accounting order to defer certain pension costs above those included in its base rates, until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007 (also see Note 8 below). On April 7, 2005, the NHPUC issued an order denying UES' Petition for an accounting order. In its analysis denying UES' request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that a full examination of UES' income and expenses would be undertaken when UES files a rate case. As of December 31, 2005, UES has recorded deferred pension costs of $1.0 million.

On November 4, 2005, UES filed a request for a base rate increase of $4.65 million. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving this request. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding. The Company expects a decision in 2006.

On January 7, 2005, the NHPUC approved UES' petition for a one year extension of Transition Service and Default Service for rate class G1, and the associated solicitation process whereby UES intends to secure energy supplies for such extended service. As a result, UES' Transition Service supply obligation for all rate classes will end at the same time on April 30, 2006. The Company recovers the costs of Transition Service and Default Service in its rates at cost on a pass-through basis and therefore changes in these expenses do not affect earnings.

On April 1, 2005, UES filed a petition with the NHPUC for approval of a plan for procurement of Default Service power supply for service, commencing on May 1, 2006 for all rate classes. A settlement supporting the plan between UES, the Office of Consumer Advocate and the NHPUC Staff, was approved by the NHPUC on

September 9, 2005. Under the approved plan, UES will procure Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis.

Under the 2002 restructuring plan approved by the NHPUC, Unitil Power sold the entitlements to its long-term power supply portfolio to Mirant and UES purchased supplies for Transition and Default Service from Mirant for up to three years. Following the Chapter 11 bankruptcy filing by Mirant in July, 2003, Mirant agreed to continue to perform all obligations under its contracts with Unitil Power and UES pursuant to a settlement approved by the bankruptcy court in December 2003. As a result of the Mirant bankruptcy, UES and Unitil Power also pursued claims with Mirant with regards to a potential future default. In January 2005, UES, Unitil Power and Mirant filed a settlement with the bankruptcy court under which Mirant has agreed to put in place a replacement guarantee, or comparable security, to guarantee performance of its responsibilities under the agreement beginning May 2006. That settlement was approved by the bankruptcy court on January 18, 2005. On January 3, 2006, Mirant emerged from Chapter 11.

FERC—Wholesale Power Market Restructuring—FG&E, UES and Unitil Power are members of the NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the OATT, to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations, and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The regional bulk power system is operated by an independent corporate entity, the ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a RTO was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO in orders issued March 24, 2004 and November 3, 2004 to begin operation of the RTO structure effective February 1, 2005. As a result of the formation of the RTO, companies seeking transmission service throughout New England will be able to obtain that service under common terms, with much of their focus on dealing with ISO-NE, in cooperation with the local transmission providers. Several parties have appealed various issues associated with the FERC's approval of the RTO to Federal District Court of Appeals. Those proceedings are ongoing.

On March 1, 2004, ISO-NE filed a proposal to implement LICAP in New England to allow for the imposition of incentive pricing for transmission constrained areas. Both UES and FG&E are located in a non-constrained area of the power pool which should have modest LICAP prices for several years under the filed proposal. UES and FG&E have intervened in the proceeding. On October 21, 2005 the FERC issued an order directing that Settlement discussions take place and indicating that implementation of LICAP, if it proceeds, will not be earlier than October 1, 2006. This case continues to be contested at the FERC.

The formation of an RTO, LICAP and other wholesale market changes, including changes to transmission rates, is not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy costs approved by the MDTE and NHPUC. It is possible, however, that retail rates will be significantly increased over the next several years if LICAP is implemented consistent with the Initial Decision.

FERC—Other—In August 2003, NU filed with FERC to revise its comprehensive network service transmission rates to establish and implement a formula based rate, replacing a fixed rate tariff. A settlement among certain parties was approved by the FERC in September 2004, which reduced the allowed return on equity in the formula rates and resulted in refunds to the tariff customers, including UES.

On March 30, 2005, NU filed an executed DSA settlement between UES and NU with the FERC for effect on June 1, 2005. The DSA provides for cost recovery by NU for facilities used by UES that had been reclassified from transmission plant to distribution plant. On April 20, 2005 UES intervened in support of the DSA. Costs to UES under the DSA are estimated to be approximately $2 million annually. These costs are expected to be recovered through reconciling cost recovery mechanisms. On May 19, 2005 the FERC accepted NU's DSA filing and the rates went into effect on June 1, 2005.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of December 31, 2005, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan (MCP) that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

During 2005, FG&E continued developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

On May 13, 2004 FG&E discovered an unauthorized excavation by another property owner on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated onto property owned by FG&E. FG&E promptly reported this discovery to the DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. The Completion Report for this release was submitted May 9, 2005.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1822 through 1978. In addition, any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Former Electric Generating Station—In 2003, FG&E completed environmental remediation action to abate and remove asbestos-containing and other hazardous materials at a former electric generating station located at Sawyer Passway in Fitchburg, Massachusetts, which FG&E sold in 1983 to a general partnership, Rockware. FG&E received significant coverage from its insurance carrier for this remediation project and the resolution of this matter did not have a material adverse effect on the Company's financial position.

Note 6: Bad Debts

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2003—2005.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	Additions		Accounts Written Off	Balance at End of Period
		(A) Provision	Recoveries		
Year Ended December 31, 2005					
Electric	**$392,824**	**$ 714,917**	**$116,290**	**$ 881,240**	**$342,791**
Gas	**89,602**	**721,171**	**116,366**	**817,108**	**110,031**
Other	**18,297**	**9,602**	**—**	**10,973**	**16,926**
	$500,723	**$1,445,690**	**$232,656**	**$1,709,321**	**$469,748**
Year Ended December 31, 2004					
Electric	$395,432	$ 821,077	$121,974	$ 945,659	$392,824
Gas	132,964	524,905	96,411	664,678	89,602
Other	13,080	10,500	—	5,283	18,297
	$541,476	$1,356,482	$218,385	$1,615,620	$500,723
Year Ended December 31, 2003					
Electric	$271,679	$ 719,761	$ 87,922	$ 683,930	$395,432
Gas	100,300	609,037	67,398	643,771	132,964
Other	61,630	90,000	—	138,550	13,080
	$433,609	$1,418,798	$155,320	$1,466,251	$541,476

(A) The amounts charged to the Provision for Doubtful Accounts include amounts related to the energy commodity portion of accounts receivable which are recovered through rate reconciling mechanisms.

Note 7: Income Taxes

Federal Income Taxes were provided for the following items for the years ended December 31, 2005, 2004 and 2003, respectively:

	2005	2004	2003
Current Federal Tax Provision (000's):			
Operating Income	**$3,671**	$ 438	$(2,898)
Total Current Federal Tax Provision	**3,671**	438	(2,898)
Deferred Federal Tax Provision (000's)			
Accelerated Tax Depreciation	**(668)**	2,805	3,329
Abandoned Properties	**(796)**	(769)	(778)
Accrued Revenue	**1,296**	1,779	2,034
Allowance for Funds Used During Construction	**(8)**	(16)	(23)
Post Retirement Benefits Other Than Pensions	**(395)**	(262)	(217)
Deferred Pensions	**694**	259	55
Regulatory Assets and Liabilities	**—**	(194)	146
Insurance Proceeds	**—**	—	1,172
Contributions in Aid of Construction	**(165)**	(120)	(201)
Net Operating Loss Carryforward	**—**	92	(331)
Alternative Minimum Tax	**—**	(355)	(125)
Other, net	**(180)**	(151)	507
Total Deferred Federal Tax Provision	**(222)**	3,068	5,568
Total Federal Tax Provision	**$3,449**	$3,506	$ 2,670

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2005, 2004 and 2003 are shown in the table below. In addition to the provisions for state income taxes, the Company recorded provisions of $179,000, $179,000 and $140,000 in 2005, 2004 and 2003, respectively for state Business Enterprise taxes which are included in Local Property and Other Taxes on the consolidated statements of earnings.

Federal and State Tax Provisions (000's)	2005	2004	2003
Federal			
Current	**$3,671**	$ 438	$(2,898)
Deferred	**(222)**	3,068	5,568
Total Federal Tax Provision	**3,449**	3,506	2,670
State			
Current	**844**	602	74
Deferred	**(18)**	98	807
Total State Tax Provision	**826**	700	881
Total Provision for Federal and State Income Taxes	**$4,275**	$4,206	$ 3,551

The differences between the Company's provisions for Income Taxes and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2005	2004	2003
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**5**	5	5
Abandoned Property	**(6)**	(6)	(7)
Other, Net	**—**	1	(1)
Effective Income Tax Rate	**33%**	34%	31%

Temporary differences which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	2005	2004
Accelerated Depreciation	**$23,937**	$25,681
Deferred Restructuring Charges	**13,204**	11,697
Regulatory Assets and Liabilities	**8,700**	9,164
Employee Benefit Plans	**2,484**	3,395
Contributions in Aid of Construction	**(2,319)**	(2,108)
Retirement Loss	**3,899**	3,407
Abandoned Property	**—**	1,535
Percentage Repair Allowance	**1,669**	1,812
Net Operating Loss Carryforward	**—**	(239)
Alternative Minimum Tax Credit	**—**	(480)
Other	**723**	2,292
Total Deferred Income Tax Liabilities	**$52,297**	$56,156

Note 8: Pension and Postretirement Benefit Plans

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

Defined Benefit Pension Plan—The Company sponsors the Unitil Corporation Retirement Plan (the Plan), a defined benefit pension plan covering substantially all its employees. Under the Plan retirement benefits are based upon an employee's level of compensation and length of service. The Company records annual expense and accounts for its defined benefit pension plan in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The following table represents information on the Plan's Projected Benefit Obligation (PBO), fair value of plan assets and the Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2005	2004
PBO at Beginning of Year	**$ 49,757**	$47,300
Service Cost	**1,458**	1,302
Interest Cost	**3,085**	3,028
Plan Amendments	**110**	—
Benefits Paid	**(2,404)**	(2,280)
Actuarial (Gain) or Loss	**6,580**	407
PBO at End of Year	**$ 58,586**	$49,757

Change in Plan Assets (000's):	2005	2004
Fair Value of Plan Assets at Beginning of Year	**$ 42,304**	$39,337
Actual Return on Plan Assets	**2,135**	3,247
Employer Contributions	**2,500**	2,000
Benefits Paid	**(2,404)**	(2,280)
Fair Value of Plan Assets at End of Year	**$ 44,535**	$42,304

PBO and Funded Status (000's):	2005	2004
Fair Value of Plan Assets	**$ 44,535**	$42,304
PBO	**58,586**	49,757
Funded Status	**(14,051)**	(7,453)
Unrecognized Net (Gain) Loss	**24,431**	17,727
Unrecognized Transition (Asset) Obligation	**—**	—
Unrecognized Prior Service Cost	**719**	716
Net Amount Recognized as Prepaid Pension Asset	**$ 11,099**	$10,990

The following table represents information on the Plan's Accumulated Benefit Obligation (ABO), its funded status, the Company's Additional Minimum Liability (AML) and associated Regulatory Assets. The ABO is the Plan's obligation for employee service provided through December 31, 2005. An unfunded ABO represents an amount to be recognized as an additional minimum liability.

ABO and Funded Status (000's):	2005	2004
ABO	**$ 49,796**	$ 42,710
Fair Value of Plan Assets	**(44,535)**	(42,304)
Unfunded ABO/AML (Recognized as Regulatory Asset)	**$ 5,261**	$ 406

In December 2003 and 2002, UES and FG&E filed requests with their respective state regulatory commissions for approval of accounting orders to mitigate certain accounting requirements related to pension plan assets which had been triggered by the substantial decline in the capital markets. UES and FG&E were granted approval of this regulatory accounting treatment in January 2003 and 2004. As a result of these approvals, the Company has recorded as a Regulatory Asset the amount of the Plan's unfunded Accumulated Benefit Obligation (ABO) plus one dollar. These approvals allow UES and FG&E to treat their Additional Minimum Liability (AML) as Regulatory Assets under FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation", (SFAS No. 71) and avoid the reduction in equity through other comprehensive income that would otherwise be required by SFAS No. 87.

On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the Pension / PBOP Adjustment Factor (PAF), to recover the costs associated with the Company's pension, and postretirement benefits other than pensions (PBOP), costs on an annually reconciling basis. As a result of this order, FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and FASB Statement No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions", (SFAS No. 106) and amortizes increases and /or decreases in that deferral balance into the PAF for recovery over a three year period. The PAF provides for an annual filing and rate adjustment with the MDTE and requires that carrying charges on prepaid or (accrued) pension and PBOP assets and liabilities be collected from, or refunded to, utility customers. In 2005, FG&E received approval of its first annual filing and rate adjustment.

The Company initiated similar discussions for a reconciling rate mechanism for the pension costs of UES with the NHPUC. On December 11, 2004, UES filed with the NHPUC a Petition for an Accounting Order to defer certain pension costs above those included in its base rates for 2004 until its next base rate case (also see Note 5 above). In that petition the Company stated its intention to explore with the NHPUC and other interested parties, a reconciling rate mechanism for pension costs incurred by UES to achieve the same benefits for UES and its customers that have been achieved by implementing the PAF for FG&E. On April 7, 2005, the NHPUC issued an order denying UES' Petition for an accounting order. In its analysis denying UES' request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that the size and impact of increased pension expense on UES is not clear and that a full examination of UES' income and expenses will be undertaken when UES files a rate case.

As a result of this order, on November 4, 2005, UES filed its request for a base rate increase of $4.65 million to recover pension costs and other increases in costs since its last rate case. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving this request. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. As of December 31, 2005, UES has recorded deferred pension costs of $1.0 million. The NHPUC has historically permitted the recovery of prudently incurred expenditures related to pension benefits for UES' employees. It is anticipated that the final determination of the amount and method of recovering UES' pension costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding.

The following tables show the components of net periodic pension cost (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

Components of NPPC (000's)	**2005**	**2004**	**2003**
Service Cost	**$ 1,458**	$ 1,302	$ 1,151
Interest Cost	**3,085**	3,028	2,940
Expected Return on Plan Assets	**(3,404)**	(3,393)	(3,573)
Amortization of Prior Service Cost	**107**	101	102
Amortization of Transition (Asset) Obligation	**—**	—	—
Amortization of Net (Gain) Loss	**1,146**	944	487
Subtotal NPPC	**2,392**	1,982	1,107
Amounts Capitalized and Deferred	**(1,751)**	(1,926)	(758)
NPPC Recognized	**$ 641**	$ 56	$ 349

Included in the amounts above for Amounts Capitalized and Deferred are $814,000 and $1,161,000 recorded as Regulatory Assets on the Company's Balance Sheet for 2005 and 2004, respectively. The remaining amounts represent amounts capitalized to construction overheads.

Key Assumptions (Weighted Average)	**2005**	**2004**	**2003**
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.50%**	6.50%	6.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Used to Determine NPPC for years ended December 31:			
Discount Rate	**6.00%(1)**	6.50%	7.00%
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.75%	8.75%
Rate of Compensation Increase	**3.50%**	3.50%	4.00%

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%. This change is reflected in the net periodic pension cost amounts shown in the table above.

The following table represents the Plan's weighted-average investment asset allocations at December 31:

	Target Allocation	**Actual Allocation at December 31**		
	2006	**2005**	**2004**	**2003**
Equity Securities	58-62%	**60%**	61%	61%
Debt Securities	38-42%	**40%**	39%	39%
Real Estate	0-2%	**0%**	0%	0%
Other	0-2%	**0%**	0%	0%
Total		**100%**	**100%**	**100%**

The desired investment objective is a long-term rate of return on assets that is approximately 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plan has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The following tables represent Plan contributions and benefit payments (000's):

	2005	**2004**	**2003**
Employer Contributions	**$2,500**	$2,000	$1,200
Participant Contributions	**$ —**	$ —	$ —
Benefit Payments	**$2,404**	$2,280	$2,270

Estimated Future Benefit Payments					
2006	**2007**	**2008**	**2009**	**2010**	**2011-2015**
$2,504	$2,614	$2,772	$2,841	$3,049	$17,362

Postretirement Benefits—The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) to provide health care and life insurance benefits to active employees. Prior to October 1, 2003, the Company funded certain postretirement benefits through the Unitil Retiree Trust (URT). The URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. Effective January 1, 2004, the PBOP Plan was amended to provide certain healthcare and life insurance benefits, which were previously provided by the URT. The

Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan. Included on the Company's Consolidated Balance Sheets at December 31, 2005 and December 31, 2004 are accrued liabilities of $4.9 million and $3.2 million, respectively, related to the PBOP Plan.

As discussed above, on October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis.

On March 15, 2004 UES filed a petition with the NHPUC for recovery of PBOP costs. UES proposed an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004. The NHPUC approved this filing, effective May 1, 2004.

As discussed above, on November 4, 2005, UES filed a request for a base rate increase of $4.65 million. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving this request. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding.

The following table represents information on the PBOP Plan's fair value of plan assets and the PBOP Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	**2005**	**2004**
PBO at Beginning of Year	**$ 27,917**	$ 31,991
Service Cost	**993**	899
Interest Cost	**1,795**	1,827
Plan Amendments	**(1,797)**	—
Benefits Paid	**(1,334)**	(1,257)
Actuarial (Gain) or Loss	**9,954**	(5,543)
PBO at End of Year	**$ 37,528**	$ 27,917
Change in Plan Assets (000's):		
Fair Value of Plan Assets at Beginning of Year	**$ 1,101**	$ —
Actual Return on Plan Assets	**37**	3
Employer Contributions	**2,500**	2,355
Benefits Paid	**(1,334)**	(1,257)
Fair Value of Plan Assets at End of Year	**$ 2,304**	$ 1,101
Obligation and Funded Status (000's):		
Fair Value of Plan Assets	**$ 2,304**	$ 1,101
PBO	**37,528**	27,917
Funded Status	**(35,224)**	(26,816)
Unrecognized Net (Gain) Loss	**6,045**	(3,913)
Unrecognized Transition (Asset) Obligation	**150**	171
Unrecognized Prior Service Cost	**24,144**	27,342
Net Amount Recognized	**$ (4,885)**	$ (3,216)

The components of net periodic postretirement benefit cost (NPPBC) are as follows:

Components of NPPBC (000's)	2005	2004	2003
Service Cost	**$ 993**	$ 899	$ 246
Interest Cost	**1,795**	1,827	558
Expected Return on Plan Assets	**(41)**	—	—
Amortization of Prior Service Cost	**1,401**	1,458	365
Amortization of Transition (Asset) Obligation	**21**	21	21
Amortization of Net (Gain) Loss	**—**	—	2
Subtotal NPPC	**4,169**	4,205	1,192
Amounts Capitalized and Deferred	**(2,051)**	(2,498)	(942)
NPPBC Recognized	**$ 2,118**	$ 1,707	$ 250

Included in the amounts above for Amounts Capitalized and Deferred are $408,000 and $718,000 recorded as Regulatory Assets on the Company's Balance Sheet for 2005 and 2004, respectively. The remaining amounts represent amounts capitalized to construction overheads.

In addition to the amounts shown above, the Company also recorded expense for payments to URT of $1.3 million in 2003.

The following table includes assumptions used in determining the various PBOP values.

Key Assumptions (Weighted Average)	2005	2004	2003
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.50%**	6.50%	6.50%
Rate of Compensation Increase	**N/A**	N/A	N/A
Health Care Cost Trend Rate Assumed for Next Year	**9.00%**	8.00%	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	2016	2013	2013
Used to Determine NPPBC for years ended December 31:			
Discount Rate	**6.00%(1)**	6.50%	7.00%
Expected Long-Term Rate of Return on Plan Assets	**8.50%/5.50%(2)**	N/A	N/A
Rate of Compensation Increase	**N/A**	N/A	N/A
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	9.00%	10.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	2013	2013	2013

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%. This change is reflected in the net periodic postretirement benefit cost amounts shown in the table above.

(2) Funding of the PBOP Plan is made into two VEBT's; one is a union VEBT and the other is a non-union VEBT. The expected long-term rate of return on plan assets for the union VEBT is 8.50%. The non-union VEBT is subject to income taxes and therefore the expected long-term rate of return on plan assets is 5.50%, reflecting the effect of taxes.

Assumed health care cost trend rates have a significant effect on the amounts reported. A one-percentage-point change in the assumed health care cost trend rates would have the following effects:

1-Percentage Point Increase (000's)	2005	2004	2003
Effect on Total of Service and Interest Cost	**$ 526**	$ 564	$ 150
Effect on Postretirement Benefit Obligation	**$ 5,917**	$ 4,079	$ 4,968
1-Percentage Point Decrease (000's)			
Effect on Total of Service and Interest Cost	**$ (413)**	$ (438)	$ (118)
Effect on Postretirement Benefit Obligation	**$(4,737)**	$(3,290)	$(4,007)

The following tables represent PBOP contributions and benefit payments made in 2003 – 2005 and estimated future benefit payments. The employer contributions and benefit payments listed below reflect the Company's assumptions of the URT obligations, effective October 1, 2003. In 2003, the Company paid URT $1.3 million.

(000's)	Expected 2006	2005	2004	2003
Employer Contributions	**$2,500**	**$2,500**	$2,355	$331
Participant Contributions	**$ —**	**$ —**	$ —	$ —

(000's)	2005	2004	2003
Benefit Payments	**$1,334**	$1,257	$331

Estimated Future Benefit Payments					
2006	2007	2008	2009	2010	2011-2015
$1,319	$1,414	$1,520	$1,614	$1,793	$10,722

Supplemental Executive Retirement Plan—The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors. The cost associated with the SERP amounted to approximately $190,000, $194,000 and $140,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

The following table represents information on the SERP's Projected Benefit Obligation (PBO), fair value of plan assets and the plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2005	2004
PBO Obligation at Beginning of Year	**$ 1,218**	$ 1,193
Service Cost	**90**	89
Interest Cost	**80**	75
Plan Amendments	**—**	—
Benefits Paid	**(72)**	(72)
Actuarial (Gain) or Loss	**594**	(67)
PBO at End of Year	**$ 1,910**	$ 1,218

Change in Plan Assets (000's):	2005	2004
Fair Value of Plan Assets at Beginning of Year	**$ —**	$ —
Actual Return on Plan Assets	**—**	—
Employer Contributions	**72**	72
Benefits Paid	**(72)**	(72)
Fair Value of Plan Assets at End of Year	**$ —**	$ —

Obligation and Funded Status (000's):	2005	2004
Fair Value of Plan Assets	**$ —**	$ —
PBO	**1,910**	1,218
Funded Status	**(1,910)**	(1,218)
Unrecognized Net (Gain) Loss	**730**	141
Unrecognized Transition (Asset) Obligation	**17**	34
Unrecognized Prior Service Cost	**20**	18
Net Amount Recognized	**$(1,143)**	$(1,025)

The components of net periodic SERP cost are as follows:

Components of Net Periodic SERP Cost (000's)	2005	2004	2003
Service Cost	**$ 90**	$ 89	$ 59
Interest Cost	**80**	75	69
Expected Return on Plan Assets	**—**	—	—
Amortization of Prior Service Cost	**(2)**	3	(5)
Amortization of Transition Obligation	**17**	17	17
Amortization of Net Loss	**5**	10	—
Net Periodic SERP Cost	**$190**	$194	$140

The following table includes information regarding Unitil's SERP costs as well as key actuarial assumptions:

Additional Information (000's):	2005	2004	2003
Accumulated Benefit Obligation	**$ 800**	$ 673	$ 675
Weighted-Average Assumptions			
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.50%**	6.50%	6.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Used to Determine Net Periodic SERP Cost for years ended December 31:			
Discount Rate	**6.50%**	6.50%	7.00%
Expected Long-Term Rate of Return on Plan Assets	**N/A**	N/A	N/A
Rate of Compensation Increase	**3.50%**	3.50%	4.00%

The following tables represent SERP contributions and benefit payments made in 2003 – 2005 and estimated future benefit payments (000's):

	2005	2004	2003
Employer Contributions	**$ 72**	$ 72	$ 64
Participant Contributions	**$ —**	$ —	$ —

	2005	2004	2003
Benefit Payments	**$ 72**	$ 72	$ 64

Estimated Future Benefit Payments					
2006	2007	2008	2009	2010	2011-2015
$69	$67	$65	$62	$60	$981

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k)) under Section 401(k) of the Internal Revenue Code, covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. The Company matches contributions, with a maximum matching contribution of 3% of current compensation. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company Common Stock fund. Participants are 100% vested in contributions made on their behalf, once they have completed three years of service. The Company's share of contributions to the plan was $503,000, $499,000 and $487,000 for the years ended December 31, 2005, 2004, and 2003, respectively.

Note 9: Earnings Per Share

The following table reconciles basic and diluted earnings per share, assuming all dilutive outstanding stock options were converted to common shares per SFAS No. 128, "Earnings per Share."

(000's except share and per share data)	2005	2004	2003
Earnings Available to Common Shareholders	**$ 8,397**	$ 8,011	$ 7,722
Weighted Average Common Shares Outstanding—Basic	**5,551,420**	5,509,321	4,877,933
Plus: Diluted Effect of Incremental Shares—from Assumed Conversion	**16,298**	15,514	18,396
Weighted Average Common Shares Outstanding—Diluted	**5,567,718**	5,524,835	4,896,329
Earnings per Share—Diluted	**$ 1.51**	$ 1.45	$ 1.58

Weighted average options to purchase 72,500, 35,000 and 72,500 shares of Common Stock were outstanding during 2005, 2004 and 2003, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive.

Note 10: Segment Information

Unitil reported four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil is engaged principally in the retail sale and distribution of electricity in New Hampshire and both electricity and natural gas service in Massachusetts through its retail distribution subsidiaries UES and FG&E. Unitil Resources is the Company's wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty, Unitil Service and the holding company are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. Unitil Resources and Usource are included in the Non-Regulated column below. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries' use.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on factors under PUHCA rules and contained in cost-of-service studies, which were included in rate applications approved by the NHPUC and MDTE. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2005, 2004 and 2003. Included in Non-regulated Segment Profit (Loss) for the year ended December 31, 2005 are a segment profit of $52,000 from Usource and a segment loss of ($59,000) from Unitil Resources, Inc.

Year Ended December 31, 2005 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$197,339**	**$32,767**	**$ —**	**$2,039**	**$232,145**
Segment Profit (Loss)	**6,957**	**911**	**536**	**(7)**	**8,397**
Identifiable Segment Assets	**328,208**	**98,184**	**22,516**	**1,173**	**450,081**
Capital Expenditures	**17,211**	**6,936**	**220**	**—**	**24,367**
Year Ended December 31, 2004 (000's)					
Revenues	$183,889	$28,685	$ —	$1,563	$214,137
Segment Profit (Loss)	6,649	1,202	300	(140)	8,011
Identifiable Segment Assets	340,800	94,239	21,069	902	457,010
Capital Expenditures	17,566	5,111	245	—	22,922
Year Ended December 31, 2003 (000's)					
Revenues	$190,864	$28,612	$ 30	$1,148	$220,654
Segment Profit (Loss)	6,500	1,600	254	(632)	7,722
Identifiable Segment Assets	371,324	84,441	26,335	1,777	483,877
Capital Expenditures	17,427	4,083	410	19	21,939

Note 11: Quarterly Financial Information (unaudited; 000's except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		**June 30,**		**September 30,**		**December 31,**	
	2005	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**
Total Operating Revenues	**$60,000**	$59,493	**$51,439**	$48,606	**$56,654**	$50,049	**$64,052**	$55,989
Operating Income	**$ 4,504**	$ 4,626	**$ 3,311**	$ 3,303	**$ 3,240**	$ 2,955	**$ 4,486**	$ 4,309
Net Income Applicable to Common	**$ 2,671**	$ 2,747	**$ 1,497**	$ 1,546	**$ 1,562**	$ 1,207	**$ 2,667**	$ 2,512
	Per Share Data:							
Earnings Per Common Share	**$ 0.48**	$ 0.50	**$ 0.27**	$ 0.28	**$ 0.28**	$ 0.22	**$ 0.48**	$ 0.45
Dividends Paid Per Common Share	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345

Note 12: Subsequent Event

Approval of Temporary Base Distribution Rates—Unitil Energy Systems, Inc.

As discussed above, on November 4, 2005, UES filed a request for a base rate increase of $4.65 million. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving this request. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). In addition, management is required to report their assessment, including their evaluation criteria, on the design and operating effectiveness of the Company's internal control over financial reporting in Form 10-K.

The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The Company's internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles. The Company's internal control over financial reporting includes policies and procedures which provide reasonable assurances that transactions are properly initiated, authorized, recorded, reported and disclosed, and provide reasonable assurances regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

During 2005, management conducted an assessment of the Company's internal control over financial reporting reflected in the financial statements, based upon criteria established in the "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on management's assessment, which included a comprehensive review of the design and operating effectiveness of the Company's internal control over financial reporting, management believes the Company's internal control over financial reporting is designed and operating effectively as of December 31, 2005.

Vitale, Caturano and Company, an independent registered public accounting firm, has audited management's assessment of the effectiveness of the internal control over financial reporting as stated in their report which is included herein.

Item 9B. Other Information

None

PART III

Item 10. Directors and Executive Officers of the Registrant

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the 2005 Proxy Statement as filed with the Securities and Exchange Commission on February 22, 2006.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Report of the Compensation Committee" section of the 2005 Proxy Statement as filed with the Securities and Exchange Commission on February 22, 2006.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the "Information About Directors" section of the 2005 Proxy Statement as filed with the Securities and Exchange Commission on February 22, 2006 as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions

None

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the 2005 Proxy Statement as filed with the Securities and Exchange Commission on February 22, 2006.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2005 and 2004
- Consolidated Statements of Earnings for the years ended December 31, 2005, 2004, and 2003
- Consolidated Statements of Capitalization—December 31, 2005 and 2004
- Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004, and 2003
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2005, 2004, and 2003
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992 and April 30, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.4	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.5	Articles of Exchange of CECo, E&H, and the Company—Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.6	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (FG&E) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.7	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, FG&E and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002

Exhibit Number	Description of Exhibit	Reference*
4.2	FG&E Purchase Agreement dated March 20, 1992 for the 8.55% Senior Notes due March 31, 2004.	Exhibit 4.18 to Form 10-K for 1993
4.3	FG&E Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.4	FG&E Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.5	FG&E Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.6	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.7	FG&E Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.8	FG&E Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2003
10.5	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 10-Q for September 30, 2003
10.6	Key Employee Stock Option Plan effective January 17, 1989.	Exhibit 10.56 to Form 8 dated April 12, 1989
10.7	Unitil Corporation Key Employee Stock Option Plan Award Agreement.	Exhibit 10.63 to Form 10-K for 1989
10.8	Unitil Corporation Management Performance Compensation Plan.	Exhibit 10.94 to Form 10-K/A for 1993
10.9	Unitil Corporation Supplemental Executive Retirement Plan effective as of January 1, 1987.	Exhibit 10.95 to Form 10-K/A for 1993
10.10	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.11	Unitil Corporation Management Incentive Plan.	Exhibit 10.13 to Form 10-K for 1998
10.12	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.13	Purchase and Sale Agreement For New Haven Harbor.	Exhibit 10.15 to Form 10-K for 1999
10.14	Labor Agreement effective June 1, 2000 between CECo and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.13 to Form 10-K for 2000

Exhibit Number	Description of Exhibit	Reference*
10.15	Labor Agreement effective June 1, 2000 between E&H and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.14 to Form 10-K for 2000
10.16	Labor Agreement effective June 1, 2000 between FG&E and The Utility Workers of America, AFL-CIO., Local Union No. B340, The Brotherhood of Utility Workers Council.	Exhibit 10.15 to Form 10-K for 2000
10.17	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.18	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.19	Unitil Corporation Tax Deferred Savings and Investment Plan—Trust Agreement	Exhibit 10.1 to Form 10-Q for September 30, 2004
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
23.2	Consent of Independent Registered Public Accounting Firm.	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** Copies of this debt instrument will be furnished to the Securities and Exchange Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 22, 2006

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board Directors,
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 22, 2006
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 22, 2006
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	February 22, 2006
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 22, 2006
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 22, 2006
/s/ ROSS B. GEORGE **Ross B. George**	Director	February 22, 2006
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 22, 2006
/s/ CHARLES H. TENNEY, III **Charles H. Tenney, III**	Director	February 22, 2006
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 22, 2006
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 22, 2006
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 22, 2006
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 22, 2006
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 22, 2006
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	February 22, 2006

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2005	2004	2003
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$8,553**	$8,226	$7,958
Less: Dividend Requirements on Preferred Stock	**156**	215	236
Net Income Applicable to Common Stock	**$8,397**	$8,011	$7,722
Average Number of Common Shares Outstanding - Basic	**5,551**	5,509	4,878
Dilutive Effect of Stock Options* and Restricted Stock	**17**	16	18
Average Number of Common Shares Outstanding - Diluted	**5,568**	5,525	4,896
Earnings Per Share - Basic	**$ 1.51**	$ 1.45	$ 1.58
Earnings Per Share - Diluted	**$ 1.51**	$ 1.45	$ 1.58

* Assumes all options were converted to common shares per SFAS 128.

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

(000's, except ratios)	Year Ended December 31,				
	2005	2004	2003	2002	2001
Earnings:					
Net Income before Extraordinary Item	**$ 8,553**	$ 8,226	$ 7,958	$ 6,088	$ 5,027
Extraordinary Item, net	**—**	—	—	—	(3,937)
Net Income, per Consolidated Statement of Earnings	**8,553**	8,226	7,958	6,088	1,090
Federal and State Income Taxes included in :					
Operations	**4,275**	4,206	3,551	2,490	3,421
Investment Write-down	**—**	—	—	—	1,236
Extraordinary Item	**—**	—	—	—	1,388
Interest on Long-Term Debt	**8,319**	8,394	8,088	8,254	7,637
Amortization of Debt Discount Expense	**104**	98	82	81	72
Other Interest	**1,046**	629	1,070	1,038	1,895
Total	**$22,297**	$21,553	$20,749	$17,951	$16,739
Fixed Charges:					
Interest of Long-Term Debt	**$ 8,319**	$ 8,394	$ 8,088	$ 8,254	$ 7,637
Amortization of Debt Discount Expense	**104**	98	82	81	72
Other Interest	**1,046**	629	1,070	1,038	1,895
Pre-tax Preferred Stock Dividend Requirements	**234**	325	391	419	417
Total	**$ 9,703**	$ 9,446	$ 9,631	$ 9,792	$10,021
Ratio of Earnings to Fixed Charges	**2.30**	2.28	2.15	1.83	1.67

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has six wholly-owned subsidiaries, five of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The sixth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our report dated February 3, 2006, accompanying the December 31, 2005 consolidated financial statements included in the Annual Report of Unitil Corporation and subsidiaries on Form 10-K for the year ended December 31, 2005 in the Registration Statements of Unitil Corporation and subsidiaries on Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000).

/s/ Vitale, Caturano & Company Ltd.

Boston, Massachusetts
February 21, 2006

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 17, 2005, accompanying the December 31, 2004 and 2003 consolidated financial statements included in the Annual Report of Unitil Corporation and subsidiaries on Form 10-K for the year ended December 31, 2004. We hereby consent to the incorporation by reference of said report in the Registration Statements of Unitil Corporation and subsidiaries on Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000.)

/s/ GRANT THORNTON, LLP

Boston, Massachusetts
February 21, 2006

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2006

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2006

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2006

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 22, 2006
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 22 , 2006
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 22, 2006

Shareholder Information

2006 Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at the office of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 20, 2006, at 10:30 a.m.

Investor Information

The Company's Transfer Agent, Computershare Trust Company, N.A. ("Computershare"), is responsible for all shareholder records, including the distribution of dividends, tax documents and proxy materials. Shareholder requests regarding these and other matters can be addressed by corresponding directly with Computershare at:

Mail: PO Box 43010, Providence, RI 02940-3010
Telephone: 800-736-3001
www.Computershare.com/equiserve

For information about the Company and your investment, you may also call the Company directly, toll-free, at: 800-999-6501 and ask for the Shareholder Representative; or visit the Investor Relations page at www.Unitil.com.

Shareholder Programs

Dividend Reinvestment Plan

A Dividend Reinvestment and Stock Purchase Plan is available to all holders of record of the Company's Common Stock. This Plan provides shareholders with an economical means to increase their investment in the Company each quarter by reinvesting their dividends without broker fees. For additional information or enrollment, please contact the Company or Computershare.

Dividend Direct Deposit

Dividend Direct Deposit Service is available without charge to shareholders of record of the Company's Common Stock. For further information or enrollment in this service, please contact the Company or Computershare.

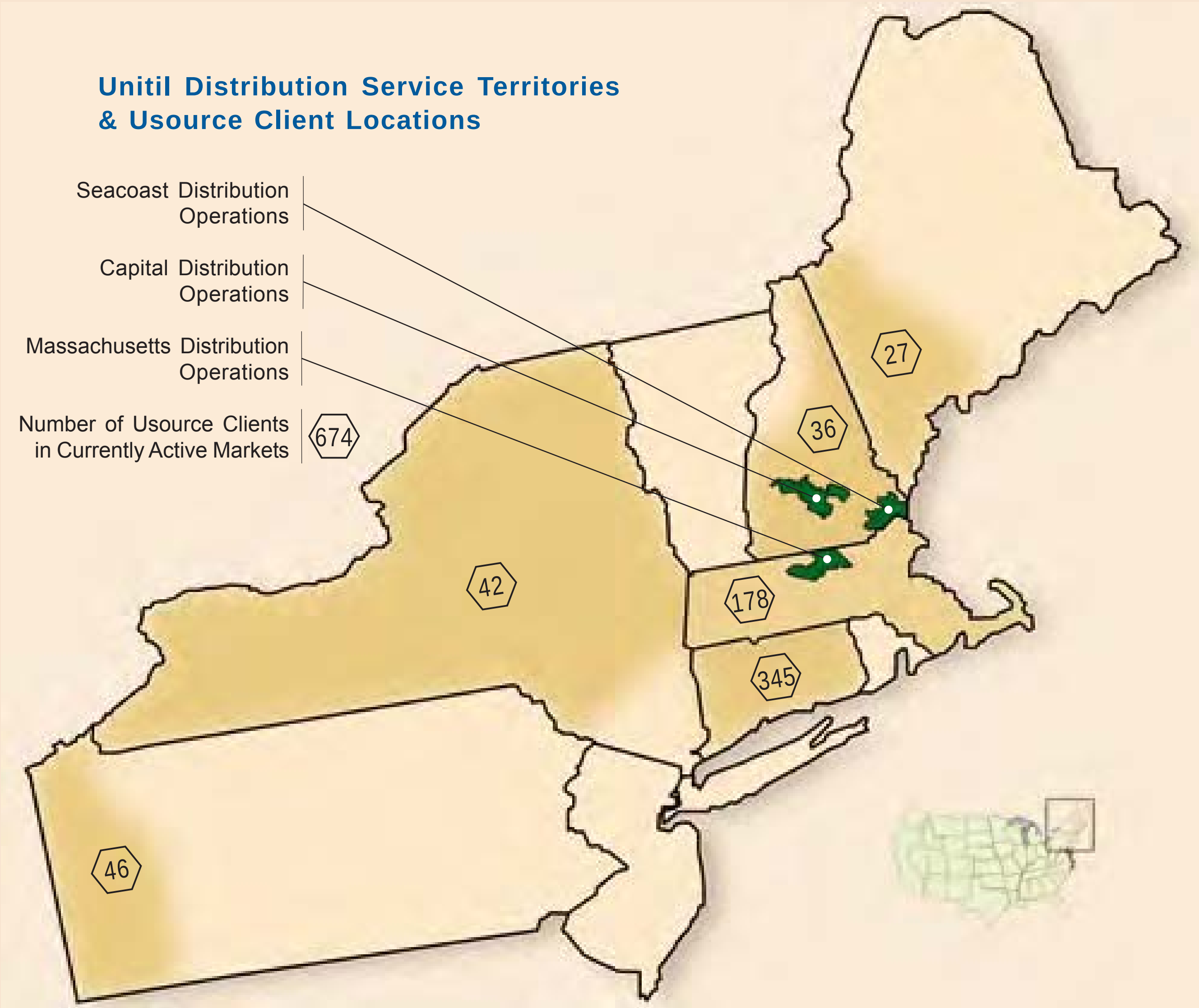
Direct Registration

Direct Registration is available without charge to shareholders of record of the Company's Common Stock. The Direct Registration System is a service within the securities industry that allows shares to be held and tracked electronically, without having to hold a stock certificate. For additional information, please contact Computershare at:

Mail: PO Box 43084, Providence, RI 02940-3084
Telephone: 800-935-9330
www.Computershare.com/equiserve

Unitil

Annual Report 2006



About the Company

Unitil (AMEX: UTL) is a public utility holding company with regulated utility subsidiaries providing electric service in New Hampshire and electric and natural gas service in Massachusetts. The Company also provides energy brokering and consulting services through its non-utility subsidiary. Additional information is available on line at www.unitil.com. Unitil's principal subsidiaries include Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc., and its non-utility non-regulated business, Usource.

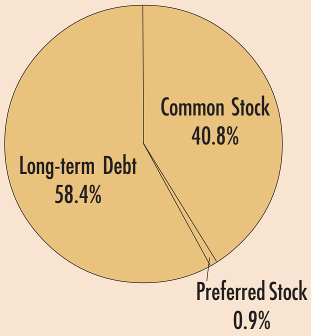
Unitil Receives National Recognition

In February 2007, Unitil was awarded the AMI Project of the Year Award at the DistribuTECH 2007 Conference & Exhibition in San Diego, California. This national award marks your Company as a leader in technical and operational innovation.

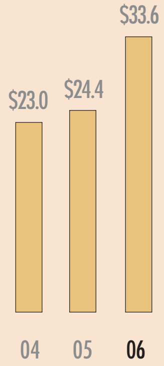
Financial Highlights

	2006	2005	2004
Financial Data (000's)			
Total Operating Revenues	**$ 260,861**	$ 232,145	$ 214,137
Total Operating Income	**$ 15,855**	$ 15,541	$ 15,193
Earnings Applicable to Common	**$ 7,900**	$ 8,397	$ 8,011
Capital Expenditures	**$ 33,642**	$ 24,367	$ 22,922
Common Share Data			
Earnings per Share	**$ 1.41**	$ 1.51	$ 1.45
Dividends Paid per Share	**$ 1.38**	$ 1.38	$ 1.38
Book Value per Share (Year-end)	**$ 17.30**	$ 17.21	$ 17.00
Market Price (Year-end)	**$ 25.35**	$ 25.16	$ 28.30
Average Common Shares Outstanding (000's)	**$ 5,612**	$ 5,568	$ 5,525
Operating Data			
Electric Distribution Sales (mWh)	**1,751,544**	1,790,405	1,742,131
Firm Gas Distribution Sales (000's of Therms)	**26,356**	24,332	23,151
Customers Served (Year-end)	**114,387**	113,593	112,288

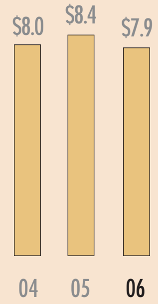
Capital Structure



Capital Expenditures
dollars in millions



Earnings Applicable to Common
dollars in millions



Our long-term goal is to achieve an annual earnings growth rate of 3% - 5%. Our overall financial performance in 2006 fell short of this goal. Earnings per share in 2006 were $1.41, as compared to $1.51 for 2005.

Earnings in 2006 reflect the impact of lower gas and electric sales, primarily due to significantly milder weather throughout the year and overall lower average monthly energy usage due to record high energy prices. Several factors partially offset the decline in sales, specifically an increase in electric distribution rates for our New Hampshire utility, increased gas sales under a new contract with our largest industrial customer, and lower overall utility operating costs.

The earnings shortfall in 2006 masked several significant accomplishments that provide the foundation for achieving our long-term financial goals. These successes included: the negotiation of rate case settlements in both Massachusetts and New Hampshire; continued growth of our non-regulated Usource business; and the continued transformation of our operations to realize improved productivity and reduced operating costs.

The overall economic health of our service territories remains positive. Customer accounts continued to grow in 2006, adding nearly 400 homes in our Massachusetts service area and 650 in New Hampshire. Although the housing market has slowed, development of a number of projects is continuing. New electric and gas commercial and industrial projects also adding to growth are under active development throughout our service areas.

It's not about technology. It's about how to optimize the organization to do things the best way.

— Glenn Appleton
Director, Meter & Service

This computer graphic, used in planning Unitil's system expansion, shows a satellite photo of Fitchburg, MA, with an overlay of Unitil's gas distribution system.

Regulation

Proactive involvement in state and federal regulatory arenas is one of our highest priorities. The utility business is fundamentally dependant on this economic regulation.

During the fourth quarter of 2006, the Company received final approval of a rate settlement that increased base distribution and other rates by about $3.1 million on an annualized basis for its utility operations in New Hampshire. The Company also recently received approval of a gas base rate settlement in Massachusetts for its gas distribution operations, which calls for a phase-in of gas distribution rate increases of $1.2 million as of February 1, 2007, and an additional $1.0 million increase on November 1, 2007. Together these rate changes represent an increase of about $5.3 million or 10% on Unitil's consolidated base electric and gas distribution revenues.

These price increases for our distribution services will contribute to more predictable financial results in the years ahead. They also underscore the excellent reputation your Company has with regulatory agencies and consumer groups.

Usource

Usource, our energy brokering business, grew significantly during 2006, adding new customer accounts and substantially increasing the volume and duration of energy transactions under

We are carefully managing the size of the company by integrating technology. — Tom Meissner, Senior VP & Chief Operating Officer

Usource management. Usource now has almost 700 major industrial and commercial customers in six northeast states. Usource revenues achieved a record level of $2.4 million, an increase of 23% over 2005. Moreover, as many of the contracts executed extend for multi-year periods, the expected future revenue stream for Usource also increased significantly. At year-end 2006, the expected future revenues for energy supply under contract over the next five years reached $6 million. Usource is well positioned to continue growing through expanded transaction volumes and acquisition of new customers throughout the Northeast, as competitive energy markets continue to mature.

Unitil's Automated Metering Infrastructure allows real-time monitoring of every gas and electric meter in the entire distribution system.

Operations Transformation

Operations Transformation is the integration of people and technology to accomplish desired work in the most efficient and cost effective manner possible. Doing it right requires good networking relationships at the most granular level in a business organization. Only the people who are actually doing the work can effectively guide the transformation of their workplace. That's what we do at Unitil – ask the people who do the work to guide the

We have refused to accept the old mantra that technology is complex. We believe technology is inherently simple.

— Raymond Morrissey, VP, Information Systems

process. Management provides the financial resources and the organizational structure that empowers its staff to get the job done. Our success is undeniable.

The pace of our transformation initiatives accelerated during 2006 and the results, in terms of both efficiency and improvements in key business processes, have exceeded expectations. In 2005 we reported that we had chosen to proceed with an Advanced Metering Infrastructure (AMI) project, our single largest capital investment. I am pleased to report that this project has been highly successful. It will be completed on time and on budget, and will result in total staffing being reduced by more than 20 positions.

In February 2007, Unitil was awarded the AMI Project of the Year Award at the DistribuTECH 2007 Conference & Exhibition in San Diego, California, one of the largest utility conferences held each year. This national award marks your Company as a leader in technical and operational innovation. A key factor to our success is the strong cross-functional teamwork in our metering, engineering, operations, accounting, and customer service functions.

Using "tablet" computers, Unitil's field personnel can research the location and history of underground facilities from their service vehicles, on site.

The AMI project will provide automated, two-way meter reading capability for all of our nearly 115,000 customers. End point data collectors at each

Unitil's geographical information system (GIS) links users across the Company, all utilizing the same data in a wide variety of business processes.

customer location communicate with servers located at our distribution substations, utilizing a power-line-carrier information transmission technology developed by Hunt Technologies. From the substation, the data is transmitted to a central processor that interprets the data and interfaces with the systems within the Company that utilize the data.

As of the end of January 2007, the AMI project in our Massachusetts service area was about 95% complete. Customer data is being collected, and billing information compiled, automatically, and remotely, for most of our customers, on time and ahead of budget.

In New Hampshire, meter installations in our Seacoast service area are well under way, with about one-third of meters installed at the end of January. Meter installations are continuing at a rate of 700 - 800 per day, and the entire system should be installed, tested, and providing data for billing purposes by May. We anticipate completing the Capital service area by summer.

On the personnel side, we have also nearly completed the reassignments of our long-term metering employees to other positions in the Company, in most cases to replace other workers who were retiring. This has allowed us to meet our goal of implementing a ma-

We have linked our business systems, using simple programming techniques to harness and integrate complex business ideas.

— Sean Baker, Manager, Software Services

jor technology initiative and workforce reduction without layoffs. Total staffing will be reduced by more than 20 positions when the project is completed.

Additional benefits of the AMI are already being realized. Customer Service representatives have the ability to generate automated read-in and read-out orders for a given meter while they are on the phone with a customer, significantly improving efficiency and customer satisfaction in the case of billing inquiries or requests for change of service account. AMI also eliminates the need for estimated bills that occur when a meter can't be read because of poor weather or access.

We are already working to assess the additional value which AMI could provide in the years ahead. For example, during a recent severe ice storm, employees used AMI data to identify outage locations, speeding restoration of service to customers. The AMI system updates meter status approximately every twenty minutes. With appropriate supplemental software, the system will be able to pinpoint outages and track outage data far more quickly and accurately than current practice, which relies largely on customer calls to identify outages.

Operations transformation is changing the way we work and the work we do.

A Sound Future

We made considerable progress on our strategic initiatives in 2006. We will continue to focus on these areas to strengthen our financial performance. We are also exploring new business and regulatory approaches to address the impact of the weather and lower

Now that we have begun to integrate our technologies, we are seeing that the whole is greater than the sum of its parts.

— Mark Lambert, Director, Customer Service

We now have the ability to present data graphically, which is more intuitive and a far more useful tool than the data, alone, would be. It gives us excellent tools for evaluating, planning, reporting, mapping, and tracking progress.

average customer usage that have contributed to earnings volatility over the last few years. These initiatives are all intended to help us achieve our target annual earnings growth rate of 3% to 5%.

Your Company is financially healthy. Our utility operations are the lowest cost in the region. Usource continues to provide the growth potential we hoped it would. We consistently exceed national benchmark scores for customer service. I believe we are well positioned to grow the value of your investment in the Company.

Robert G. Schoenberger
Chairman of the Board of Directors
President & Chief Executive Officer

February 16, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire **(State or other jurisdiction of incorporation or organization)**	**02-0381573** **(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire **(Address of principal executive offices)**	**03842-1720** **(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**American Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Based on the closing price of June 30, 2006, the aggregate market value of common stock held by non-affiliates of the registrant was $132,492,742.

The number of common shares outstanding of the registrant was 5,660,619 as of February 21, 2007.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 19, 2007, are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2006
Table of Contents

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly-owned subsidiaries of Unitil:

Unitil Corporation Subsidiaries	State and Year of Organization	Principal Type of Business
Unitil Energy Systems, Inc. (UES)	NH - 1901	Retail Electric Distribution Utility
Fitchburg Gas and Electric Light Company (FG&E)	MA - 1852	Retail Electric & Gas Distribution Utility
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-regulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering and Advisory Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts. Unitil has two distribution utility subsidiaries, UES, which operates in New Hampshire and FG&E, which operates in Massachusetts (collectively referred to as the "retail distribution utilities"). Unitil's retail distribution utilities serve approximately 99,300 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are local "pipes and wires" utility distribution companies with a combined investment in net utility plant of $231.8 million at December 31, 2006. Unitil's total revenue was $260.9 million in 2006. Earnings applicable to common shareholders for 2006 was $7.9 million. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

OPERATIONS

Electric Utility Operations

Unitil's electric utility operations are conducted through the retail distribution utilities, UES and FG&E. Revenue from Unitil's electric utility operations was $225.2 million for 2006. Earnings from electric utility operations were $7.0 million for the same 12-month period.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its franchise areas. As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities continue to deliver that supply of electricity over their distribution systems. Both UES and FG&E supply electricity to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

UES distributes electricity to approximately 71,600 customers in New Hampshire in the capital city of Concord as well as 12 surrounding towns and all or part of 16 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. UES' franchise areas consist of approximately 408 square miles. The state capital of New Hampshire is located within UES' franchise areas, and includes the executive, legislative and judicial branches and offices and facilities for all major state government services as well as several federal government facilities. In addition, UES' franchise areas are retail trading and recreation centers for the central and southeastern parts of the state. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics. UES' franchise areas include popular resort areas and beaches along the Atlantic Ocean, including the Hampton Beach recreational area. UES' 2006 retail electric operating revenue was $155.8 million, of which approximately 45.0% was derived from residential sales and 55.0% from commercial/industrial sales.

FG&E is engaged in the retail distribution of both electricity and natural gas in the city of Fitchburg and several surrounding communities. FG&E's franchise area encompasses approximately 170 square miles. Electricity is supplied and distributed by FG&E to approximately 27,700 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. FG&E's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. FG&E's 2006 retail electric operating revenue was $69.4 million, of which approximately 46.0% was derived from residential sales and 54.0% from commercial/industrial sales.

Gas Utility Operations

Natural gas is supplied and distributed by FG&E to approximately 15,000 retail customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

FG&E's 2006 gas operating revenue was $33.3 million, of which approximately 51.0% was derived from residential firm sales and 49.0% from commercial/industrial firm sales. Earnings from FG&E's gas utility operations were $0.5 million for 2006.

Seasonality

Natural gas sales in New England are seasonal, and the Company's results of operations reflect this seasonal nature. Accordingly, results of operations are typically positively impacted by gas operations during the five heating season months, from November through March. Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours.

Non-regulated and Other Non-Utility Operations

Unitil's non-regulated operations are conducted through Unitil Resources and its subsidiary Usource. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's non-regulated operations was $2.4 million in 2006. Earnings from Unitil's non-regulated operations was a net loss of ($0.2 million) in 2006. Unitil's other non-utility subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries. The earnings of these other non-utility operations are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and is reported in Other segment income (for segment information, see Part II, Item 8, Note 10 herein). Net earnings from Unitil's other non-utility operations was $0.6 million in 2006.

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)

RATES AND REGULATION

Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third party vendors. Most customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next four to six years, is $126.1 million as of December 31, 2006 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet (see Regulatory Assets table in Note 1.) Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

ELECTRIC POWER SUPPLY

The transition to retail choice required the divestiture of Unitil's existing power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility service. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the Independent System Operator—New England (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from competitive retail suppliers. Retail choice has been successful for Unitil's largest customers. As of December 2006, 45% of Unitil's largest New Hampshire customers representing 18% of total New Hampshire electric sales and 87% of Unitil's largest Massachusetts customers representing 42% of total Massachusetts electric sales are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into wholesale electric power supply contracts with various wholesale suppliers.

FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service. MDTE policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, with each 12 month contract providing 50% of the class requirements. The MDTE is investigating alternatives to the current procurement policy for all accounts, other than the large general accounts. This process could potentially lead to the procurement of FG&E Default Service power supply for longer durations in order to provide more price stability for smaller customers throughout Massachusetts for whom competitive retail options are relatively scarce.

UES currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. UES procures Default Service for its largest general service accounts through successive competitive solicitations of three-months duration and procures Default Service for all other customers through a series of two one-year contracts and two three-year contracts with each contract covering 25% of the total requirements of the group. The first two contracts were of 6-months and 18-months duration in order to stagger the start dates of future 1-year and 3-year procurements.

Regional Transmission and Power Markets

FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the Regional Transmission Organization (RTO) in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDTE and NHPUC.

GAS SUPPLY

FG&E's natural gas customers now have the opportunity to purchase their natural gas supply from third-party suppliers, though most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E purchases natural gas from domestic and Canadian suppliers under contracts of one year or less, as well as from producers and marketers on the spot market and arranges for the transportation to its distribution facilities under long-term contracts with the Tennessee interstate pipeline. FG&E has a four-year contract for liquefied natural gas (LNG) supply ending in 2008, which was approved by the MDTE. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2004 through 2006.

Sources of Gas Supply

(Expressed as percent of total MMBtu of gas purchased)

	2006	**2005**	**2004**
Natural Gas:			
Domestic firm	**84.2%**	84.8%	85.0%
Canadian firm	**2.0%**	3.4%	5.4%
Domestic spot market	**11.0%**	9.3%	5.9%
Total natural gas	**97.2%**	97.5%	96.3%
Supplemental gas	**2.8%**	2.5%	3.7%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2006	**2005**	**2004**
Cost of gas purchased and sold per MMBtu	**$11.18**	$10.83	$ 8.42
Percent Increase from prior year	**3.2%**	28.7%	17.9%

FG&E has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2006, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—FG&E continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary closure of the site. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E has recovered the environmental response costs incurred at this former MGP site in gas rates pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition FG&E has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

FG&E is in the process of developing long range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2006 in Environmental Obligations is $12.0 million related to estimated future costs for permanent remediation of the site. A corresponding regulatory asset was recorded to reflect the future rate recovery for these costs. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

The Company's ultimate liability for future environmental remediation costs may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

EMPLOYEES

As of December 31, 2006, the Company and its subsidiaries had 304 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

There are approximately 100 employees represented by labor unions. These employees are covered by collective bargaining agreements, which expire May 31, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is www.unitil.com. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the American Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 21, 2007:

Name	Age	Position
Robert G. Schoenberger	56	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	47	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	44	Senior Vice President and Chief Operating Officer
Laurence M. Brock	53	Controller and Chief Accounting Officer
Todd R. Black	42	President, Usource
George R. Gantz	55	Senior Vice President, Customer Services and Communications, Unitil Service Corp.
George E. Long, Jr.	50	Vice President, Administration, Unitil Service Corp.
Raymond J. Morrissey	59	Vice President, Information Systems
Sandra L. Whitney	43	Corporate Secretary
Dr. Robert V. Antonucci	61	Director
David P. Brownell	63	Director
Michael J. Dalton	66	Director
Albert H. Elfner, III	62	Director
Edward F. Godfrey	57	Director
Michael B. Green	57	Director
Eben S. Moulton	60	Director
M. Brian O'Shaughnessy	63	Director
Charles H. Tenney, III	59	Director
Dr. Sarah P. Voll	64	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board and Chief Executive Officer since 1997 and Unitil's President since 2003. Prior to his employment with Unitil, he was President and Chief Executive Officer of the New York Power Authority (a state owned public power enterprise) from 1993 until 1997. He is also a Trustee and Chairman of Exeter Health Resources.

Mark H. Collin has been Unitil's Senior Vice President and Chief Financial Officer since February 2003. Mr. Collin has served as Unitil's Treasurer since 1998. Since 1992, he has been Treasurer of UES and FG&E. Mr. Collin joined Unitil in 1988. Mr. Collin serves on the Board of Governors of New Hampshire Public Television.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President and Chief Operating Officer since June 2005. Mr. Meissner served as Unitil's Senior Vice President, Operations from February 2003 through June 2005. Mr. Meissner joined Unitil in 1994 and served as Unitil's Director of Engineering from 1998 to 2003. From 1985 to 1994, he was employed by the Public Service Company of New Hampshire.

Laurence M. Brock has been Unitil's Chief Accounting Officer and Controller since June 2005. Mr. Brock joined Unitil in 1995 as Vice President and Controller, and is a Certified Public Accountant in the State of New Hampshire. Prior to his employment with Unitil, Mr. Brock served as a Corporate Controller with a group of diversified financial services and manufacturing companies. Mr. Brock gained his public accounting experience with Coopers & Lybrand in Boston, Massachusetts.

Todd R. Black has been President of Usource since June 2003. He served as Vice President, Sales and Marketing for Usource from 1998 to 2003. Prior to his employment with Unitil, he served as Vice President, Services Delivery for Energy USA, the non-regulated subsidiary of Bay State Gas Company, from 1988 until 1998.

George R. Gantz has been Unitil's Senior Vice President, Customer Services and Communications since January 2003. Mr. Gantz previously served as Unitil's Senior Vice President, Communication and Regulation from 1994 to 2003. Mr. Gantz joined Unitil in 1983.

George E. Long, Jr. has been Unitil's Vice President, Administration since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources from 1998 to 2003. Prior to his employment with Unitil, Mr. Long was the Director of Compensation and Benefits at Monarch Life Insurance Company from 1985 to 1994.

Raymond J. Morrissey has been Unitil's Vice President, Information Systems since February 2003. From 1992 to 2003, he served as Unitil's Vice President of Customer Service, and from 1991 to 1992, he was the General Manager of Unitil's subsidiary, FG&E. Mr. Morrissey joined Unitil in 1985.

Sandra L. Whitney has been Unitil's Corporate Secretary and Secretary of the Board since February 2003. Ms. Whitney has been the Corporate Secretary of Unitil's subsidiary companies, FG&E, UES, Unitil Power, Unitil Realty and Unitil Service since 1994. Ms. Whitney joined Unitil in 1990.

Dr. Robert V. Antonucci has been President of Fitchburg State College since 2003. Dr. Antonucci was also President of the School Group of Riverdeep, Inc. from 2001 to 2003, and President and CEO of Harcourt Learning Direct and Harcourt Online College from 1998 to 2001. Dr. Antonucci also served as the Commissioner of Education for the Commonwealth of Massachusetts from 1992 to 1998. Dr. Antonucci also serves as a Director of Eastern Bank.

David P. Brownell was a Senior Vice President of Tyco International Ltd. from 1995 until his retirement in 2003. He had been with Tyco since 1984. Mr. Brownell is also Interim President of the University of New Hampshire Foundation.

Michael J. Dalton was Unitil's President and Chief Operating Officer from 1984 until his retirement in 2003. Mr. Dalton is a member of the Industrial Advisory Board of the University of New Hampshire College of Engineering and Physical Sciences.

Albert H. Elfner, III was the Chairman, from 1994, and Chief Executive Officer, from 1995, of Evergreen Investment Management Company until his retirement in 1999. Mr. Elfner is also a Director of NGM Insurance Company (NGM), as well as a member of the NGM Finance Committee.

Edward F. Godfrey was the Executive Vice President and Chief Operating Officer of Keystone Investments, Incorporated from 1997 until his retirement in 1998. While at Keystone Investments, he was also a Senior Vice President, Chief Financial Officer and Treasurer from 1988 to 1996. Mr. Godfrey is also a Director of VehiCare, LLC since 2006.

Michael B. Green has been the President and Chief Executive Officer of Capital Region Health Care and Concord Hospital since 1992. Mr. Green is also a member of the Adjunct Faculty, Dartmouth Medical School, Dartmouth College. He also currently serves on the Board of the Foundation for Healthy Communities, is a Director and Chair of the New Hampshire Hospital Association, a Director of New Hampshire Business Committee for the Arts, a Director of Merrimack County Savings Bank, including membership on the bank's Investment and Audit Committees, and a member of the *Concord Monitor* Board of Contributors.

Eben S. Moulton has been the Managing Partner of Seacoast Capital Corporation since 1995. Mr. Moulton is also a Director of IEC Electronics, a Director of six private companies and a Trustee of Colorado College.

M. Brian O'Shaughnessy has been the Chairman of the Board, Chief Executive Officer and President of Revere Copper Products, Inc. since 1988. Mr. O'Shaughnessy also serves on the Board of Directors of the National Association of Manufacturers, the International Copper Association, the Copper Development Association, and the Copper and Brass Fabricators Council. He also serves in New York State as Chairman of the Industrial Energy Consumer Coalition, and as a member of the Board of Directors of the Multiple Intervenors.

Charles H. Tenney, III has been Director of Operations for Brainshift.com, Inc. since 2002. He also served as a financial advisor for H&R Block Financial Advisors from 2001 to 2002. Mr. Tenney also served on the Board of Overseers of the Huntington Theater Company, Boston, Massachusetts from 2004 – 2006.

Dr. Sarah P. Voll has been the Vice President, National Economic Research Associates, Inc. (NERA) since 1999. Dr. Voll was also a Senior Consultant at NERA from 1996 to 1999. Prior to her employment with NERA, Dr. Voll was a staff member at the New Hampshire Public Utilities Commission from 1980 – 1996.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 19, 2007, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of stock certificates, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Computershare
P.O. Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

Investor Relations

For information about the Company and your investment, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at *www.unitil.com*; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available

- Internet Account Access is available at *www.computershare.com*.
- Dividend Reinvestment Plan:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Direct Registration:

  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

Risks related to the regulation of our business could impact the rates we are able to charge, our costs and our profitability.

We are subject to comprehensive regulation by federal and state regulatory authorities, which significantly influences our operating environment and our ability to recover costs from our customers. In particular, we are regulated by the FERC and state regulatory authorities with jurisdiction over public utilities, including the NHPUC and the MDTE. These authorities regulate many aspects of our operations, including, but not limited to, construction and maintenance of facilities, operations, safety, issuance of securities, accounting matters, transactions between affiliates, the rates that we can charge customers and the rate of return that we are allowed to realize. Our ability to obtain rate adjustments to maintain our current rate of return depends upon regulatory action under applicable statutes, rules and regulations, and we cannot assure you that we will be able to obtain rate adjustments or continue receiving our current authorized rates of return. These regulatory authorities are also empowered to impose financial penalties and other sanctions on us if we are found to have violated statutes and regulations governing our utility operations.

We are unable to predict the impact on our operating results from the regulatory activities of any of these agencies. Although we have attempted to actively manage the rate making process and have had recent success in obtaining rate increases, we can offer no assurances as to future success in the rate making process. Despite our requests, these regulatory commissions have authority under applicable statutes, rules and regulations to leave our rates unchanged, grant increases or order decreases in such rates. They have similar authority with respect to the recovery of our electricity and natural gas supply costs incurred by UES and FG&E in their role as a "provider of last resort" for customers who do not contract with third-party suppliers, or whose third-party supplier fails to deliver. In the event that we are unable to recover these costs or recovery of these costs were to be significantly delayed, our operating results could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have an adverse effect on our operating results.

As a result of industry restructuring, we have a significant amount of certain stranded energy supply costs, which are subject to recovery in future periods.

The stranded costs resulting from the implementation of industry restructuring mandated by the states of New Hampshire and Massachusetts are recovered by us on a pass-through basis through periodically adjusted rates. Any unrecovered balance of purchased power or stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

Our power supply portfolio related stranded costs due to the electric industry restructuring in New Hampshire and Massachusetts for which regulatory approval has been obtained for recovery were approximately $50.0 million for FG&E and $42.6 million for UES as of December 31, 2006 (See total of $92.6 million on the Power Supply Buyout Obligations line of Regulatory Assets table of Note 1). Substantially all of FG&E's stranded costs relate to owned generation assets and power purchase agreements divested by FG&E under a long-term contract buy-out agreement. Approximately $18.4 million of UES' stranded costs are attributable to the long-term power purchase agreements divested by Unitil Power under a long-term contract buyout agreement. Because FG&E and Unitil Power remain ultimately responsible for purchase power payments underlying these long-term buyout agreements, FG&E and Unitil Power could incur additional stranded costs were they required to resell such divested entitlements prior to the end of their term for amounts less than the amounts agreed to under the existing long-term buyout agreements. We expect that any such additional stranded costs would be recovered from our customers, although such recovery would require approval from the MDTE or NHPUC, the receipt of which cannot be assured.

Our electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may negatively impact our customers and correspondingly our operating results and financial condition.

Our business is influenced by the economic activity of our franchise areas. The level of economic growth in our electric and natural gas distribution franchise areas directly affects our potential for future growth in our business. As a result, adverse changes in the economy may have negative effects on our revenues, operating results and financial condition.

Declines in the valuation of capital markets could require us to make substantial cash contributions to cover our pension obligations, which could negatively impact our financial condition. In addition, the recovery of certain pension obligations is subject to regulatory risks.

We made a voluntary cash contribution to our pension plan of $2.0 million in 2004. In 2005, we were required to make a minimum cash contribution of $0.7 million to our pension plan and made an additional voluntary cash contribution of $1.8 million for a total of $2.5 million. In 2006, we were required and made a minimum cash contribution of $2.5 million to our pension plan. If the valuation of capital markets were to significantly decline from current levels, we may be required to make cash contributions to our pension plans substantially in excess of the levels currently anticipated, which could adversely affect our financial condition.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period.

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for

Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates. In the event that we are unable to recover these costs or recovery of these costs were to be significantly delayed, our operating results could be materially adversely affected. See Note 8 also.

Increases in interest rates could have a negative impact on our financial condition.

Our utility subsidiaries have ongoing capital expenditure requirements which they frequently fund by issuing short and long-term debt. Changes in interest rates do not affect interest expense associated with presently outstanding fixed rate long-term debt securities. However, changes in interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities that are issued. In addition, short-term debt borrowings are typically at variable rates of interest. As a result, changes in short-term interest rates will increase or decrease our interest expense associated with short-term borrowings. Increases in interest rates generally will increase our borrowing costs and could adversely affect our financial condition or results of operations.

Weather conditions may cause our sales to vary from year to year.

Our utility operating sales vary from year to year, depending on weather conditions. We estimate that approximately 75% of our annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, particularly during the winter heating season. Our electric sales are generally less sensitive to weather than our gas sales, but may also be affected by weather conditions in both the winter and summer seasons.

We are a holding company and have no operating income of our own. Our ability to pay dividends on our common stock is dependent on dividends received from our subsidiaries and on factors directly affecting us, the parent corporation. We cannot assure you that our current annual dividend will be paid in the future.

We are a public utility holding company and we do not have any operating income of our own. Consequently, our ability to pay dividends on our common stock is dependent on dividends and other payments received from our subsidiaries, principally UES and FG&E. The ability of our subsidiaries to pay dividends or make distributions to us will depend on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of our subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by our subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of UES and FG&E and that may be contained in future debt agreements of our subsidiaries, if any;
- limitations imposed by New Hampshire and Massachusetts state regulatory agencies, which, among other things, may prohibit the payment of dividends by subsidiaries out of capital or unearned surplus without prior approval.

In addition, we may incur indebtedness in the future. Before we can pay dividends on our common stock, we have to satisfy our debt obligations and comply with any statutory or contractual limitations.

Our current annual dividend is $1.38 per share of common stock, payable quarterly. However, our board of directors reviews our dividend policy periodically in light of the factors referred to above, and we cannot assure you of the amount of dividends, if any, that may be paid in the future.

Transporting and storing natural gas and supplemental gas supplies, as well as electricity, involve numerous risks that may result in accidents and other operating risks and costs.

Inherent in our electric and gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions, electrocutions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, and impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines, storage facilities and electric distribution equipment near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

Our business is subject to environmental regulation in all jurisdictions in which we operate and our costs of compliance are significant. Any changes in existing environmental regulation and the incurrence of environmental liabilities could negatively affect our results of operations and financial condition.

Our utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and the health and safety of our employees. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; imposition of remedial requirements; and even issuance of injunctions to ensure future compliance. Liability under certain environmental laws is strict, joint and several in nature. Although we believe we are in general compliance with all applicable environmental and safety laws and regulations, there can be no assurance that significant costs and liabilities will not be incurred in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, could result in increased environmental compliance costs. See "Environmental Matters" in the Part I, Item 1, and Note 5 of this report for further detail.

Catastrophic events could have a material adverse effect on our financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could have a material adverse effect on us, since they could inhibit our ability to continue providing electric and/or gas distribution services to our customers for an extended period, which is the principal source of our operating income.

Customers' future performance under multi-year energy brokering contracts.

The Company's non-regulated energy brokering business provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenues from this business are primarily derived from brokering fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts. The Company cannot guarantee customers' future performance under multi-year energy brokering contracts.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2006, Unitil owned, through its retail distribution utilities: two operation centers, approximately 2,155 pole miles of local transmission and distribution overhead electric lines and 518 conduit bank miles of underground electric distribution lines, along with 59 electric substations, including three mobile electric substations. FG&E's natural gas operations property includes a liquid propane gas plant, a liquid natural gas plant and 317 miles of underground gas mains. In addition, Unitil's real estate subsidiary, Unitil Realty, owns the Company's corporate headquarters building and the 12 acres on which it is located.

UES owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. UES' 37 electric distribution substations, including a 5,000 kilovolt ampere (kVA) mobile substation, constitute 257,315 kVA of capacity (includes spares and mobile) for the transformation of electric energy from the 34.5 kV sub-transmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by UES or occupied by UES pursuant to a perpetual easement.

UES has a total of approximately 1,598 pole miles of local transmission and distribution overhead electric lines and a total of 342 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by UES without objection by the owners. In the case of certain distribution lines, UES owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

Additionally, UES owns 139.2 acres of non-utility property located on the east bank of the Merrimack River in Concord, New Hampshire. Of the total acreage, 81.2 acres are located within an industrial park zone.

The physical utility properties of UES, with certain exceptions, and its franchises are pledged as security under its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of UES are outstanding.

FG&E's electric properties consist principally of 557 pole miles of local transmission and distribution overhead electric lines, 176 conduit bank miles of underground electric distribution lines and 22 transmission and distribution stations including two mobile electric substations. The capacity of these substations totals 662,650 kVA.

FG&E owns a liquid propane gas plant and a liquid natural gas plant and the land on which they are located. FG&E also has 317 miles of underground steel, cast iron and plastic gas mains.

FG&E's electric substations, with minor exceptions, are located on land owned by FG&E or occupied by FG&E pursuant to a perpetual easement. FG&E's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by FG&E without objection by the owners. FG&E leases its distribution operations center located in Fitchburg, Massachusetts.

The Company believes that its facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Note 5 to the Consolidated Financial Statements. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 4 Submission of Matters to a Vote of Security Holders

None

PART II

Item 5 Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's Common Stock is traded on the American Stock Exchange. As of December 31, 2006, there were 1,389 Common Shareholders of record.

Common Stock Data

Dividends per Common Share	2006	2005
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2006		2005	
Price Range of Common Stock	High/Ask	Low/Bid	High/Ask	Low/Bid
1st Quarter	**$26.11**	**$24.59**	$27.80	$25.50
2nd Quarter	**$26.05**	**$23.70**	$28.05	$25.31
3rd Quarter	**$24.97**	**$23.80**	$28.70	$27.00
4th Quarter	**$26.09**	**$23.82**	$28.10	$24.37

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

EQUITY COMPENSATION PLAN BENEFIT INFORMATION

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
KESOP (1)	40,388	$11.25	29,101
Restricted Stock Plan (2)	—	N/A	121,905
Equity compensation plans not approved by security holders			
1998 Option Plan (3)	107,000	$27.13	—
Total	147,388	$22.78	151,006

NOTES: (also see Note 2 to the Consolidated Financial Statements)

(1) The KESOP was approved by shareholders in July 1989. Options were granted between January 1989 and November 1997.

(2) The Restricted Stock Plan was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants

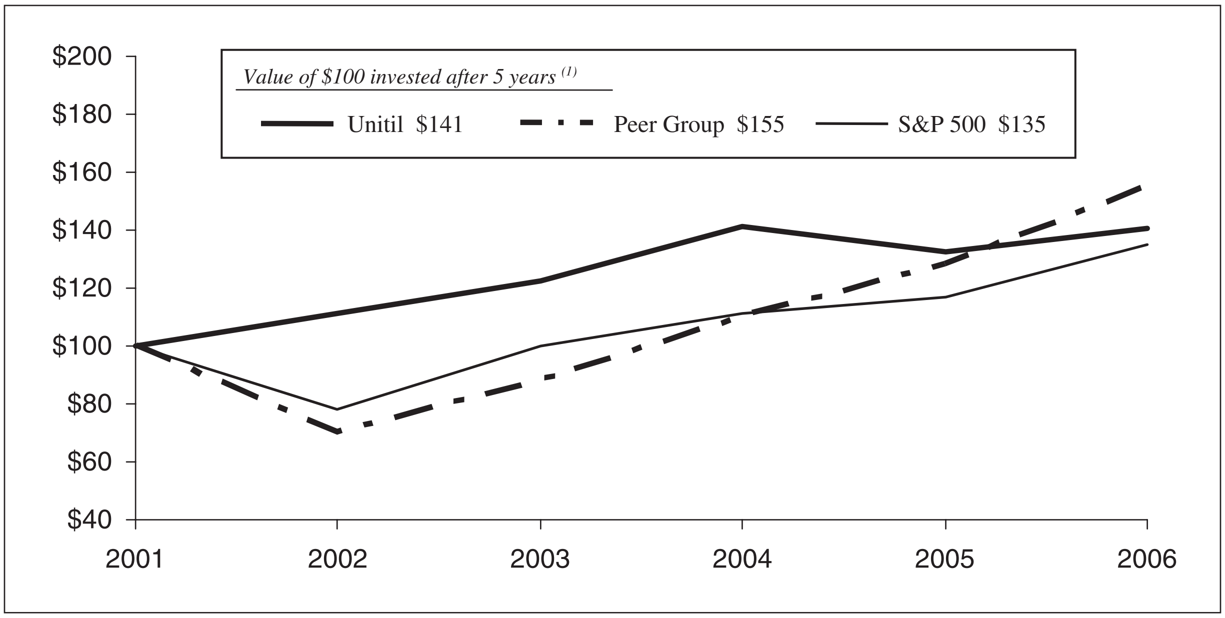
in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006; 9,020 shares of restricted stock were awarded to Plan participants in February 2007.

(3) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the Option Plan were deregistered with the Securities and Exchange Commission. The Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the Option Plan. No further grants of options will be made thereunder.

Stock Performance Graph

The following graph compares Unitil Corporation's cumulative stockholder return since December 31, 2001 with the Peer Group index, comprised of the S&P Utility Index, and the S&P 500 index. The graph assumes that the value of the investment in the Company's common stock and each index (including reinvestment of dividends) was $100 on December 31, 2001.

Comparative Five-Year Total Returns



NOTES:

(1) The graph above assumes $100 invested on December 31, 2001, in each category and the reinvestment of all dividends during the five-year period. The Peer Group is comprised of the S&P Utility Index.

Unregistered Sales of Equity Securities and Uses of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2006.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
10/1/06 – 10/31/06	—	—	—	n/a
11/1/06 – 11/30/06	—	—	—	n/a
12/1/06 – 12/31/06	—	—	—	n/a
Total	—	—	—	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

Item 6. Selected Financial Data

For the Years Ended December 31,	2006	2005	2004	2003	2002
(all data in thousands except % and per share data)					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 260,861**	$ 232,145	$ 214,137	$ 220,654	$ 188,386
Operating Income	**15,855**	15,541	15,193	15,449	13,248
(Gain) on Non-Utility Investments, net of tax	**—**	—	—	—	(82)
Other Non-operating Expense (Income)	**(19)**	147	193	(40)	185
Income Before Interest Expense, net	**15,874**	15,394	15,000	15,489	13,145
Interest Expense, net	**7,841**	6,841	6,774	7,531	7,057
Net Income	**8,033**	8,553	8,226	7,958	6,088
Dividends on Preferred Stock	**133**	156	215	236	253
Earnings Applicable to Common Shareholders	**$ 7,900**	$ 8,397	$ 8,011	$ 7,722	$ 5,835
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 352,999**	$ 324,967	$ 308,054	$ 288,657	$ 272,402
Total Assets	**$ 483,427**	$ 450,081	$ 457,010	$ 483,877	$ 481,702
Capitalization:					
Common Stock Equity	**$ 97,775**	$ 96,283	$ 94,291	$ 92,805	$ 74,350
Preferred Stock	**2,083**	2,327	2,338	3,269	3,322
Long-Term Debt, less current portion	**140,028**	125,365	110,675	110,961	104,226
Total Capitalization	**$ 239,886**	$ 223,975	$ 207,304	$ 207,035	$ 181,898
Current Portion of Long-Term Debt	**$ 336**	$ 308	$ 285	$ 3,263	$ 3,243
Short-term Debt	**$ 26,000**	$ 18,700	$ 25,675	$ 22,410	$ 35,990
Capital Structure Ratios:					
Common Stock Equity	**41%**	43%	46%	45%	41%
Preferred Stock	**1%**	1%	1%	2%	2%
Long-Term Debt	**58%**	56%	53%	53%	57%
Earnings Per Share Data:					
Earnings Per Average Share—Basic and Diluted	**$ 1.41**	$ 1.51	$ 1.45	$ 1.58	$ 1.23
Common Stock Data:					
Shares of Common Stock—Diluted (Average)	**5,612**	5,568	5,525	4,896	4,762
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.30**	$ 17.21	$ 17.00	$ 16.87	$ 15.67
Electric and Gas Sales:					
Electric Distribution Sales (kWh)	**1,751,544**	1,790,405	1,742,131	1,717,664	1,659,136
Firm Natural Gas Distribution Sales (Therms)	**26,356**	24,332	23,151	24,592	22,480

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through two utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with an operating franchise in the southeastern seacoast and capital city areas of New Hampshire. FG&E is a combination gas and electric utility with an operating franchise in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 99,300 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are local "pipes and wires" utilities with a combined investment in net utility plant of $231.8 million at December 31, 2006. Unitil's total revenue was $260.9 million in 2006. Earnings applicable to common shareholders for 2006 was $7.9 million. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Usource's total revenues were $2.4 million in 2006. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' future performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A. Risk Factors.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the three fiscal years ended December 31, 2006, 2005 and 2004 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report.

Net Income and EPS Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $7.9 million for 2006. Earnings per common share were $1.41 for 2006 compared to $1.51 for 2005. Earnings in 2006 reflect lower electric and gas sales. The lower sales in 2006 were primarily driven by milder weather compared to 2005. Earnings in 2006 also reflect higher operating and maintenance expenses and interest costs. Partially offsetting these factors was an increase in electric distribution rates in 2006 for Unitil's utility subsidiary in New Hampshire and increased gas delivery sales under a new contract with a large industrial customer in Massachusetts.

During the fourth quarter of 2006, the Company received final approval of a rate settlement that increased base distribution rates by about $3.1 million on an annualized basis for its electric utility operations in New Hampshire. The Company also recently received approval of a gas base rate settlement in Massachusetts for its gas distribution operations, which will phase-in rate increases of $1.2 million as of February 1, 2007, and an additional $1.0 million increase on November 1, 2007. Together these rate settlements represent an increase of about 10% on Unitil's consolidated electric and gas distribution revenues.

Total electric sales decreased 2.2% in 2006 compared to 2005. This decrease reflects significantly milder weather in 2006 and overall lower average monthly energy usage by customers.

Total sales of natural gas increased 8.6% in 2006 compared to 2005, primarily due to a new transportation sales contract with a large industrial customer. Absent the sales from this new contract, total gas sales were approximately 10.7% lower in 2006 compared to 2005. These lower gas sales also reflect the significantly milder winter weather in 2006. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, reflecting a record warm winter heating season.

Total electric and gas sales margin decreased $1.3 million in 2006 compared to 2005. The decline in average energy usage by customers, which was primarily driven by milder weather, negatively impacted total electric and gas sales margin by $1.7 million. This negative impact on electric and gas sales margin was partially offset by $0.4 million, net, due to changes in electric rates in 2006 compared to 2005, gas delivery sales under a new transportation contract with a large industrial customer, and higher revenues from Usource.

Total Operations & Maintenance expense increased $1.2 million in 2006 compared to 2005. This increase reflects higher retiree and employee benefit costs of $0.8 million, higher salaries and compensation expenses of $0.7 million and an increase in all other operating expenses of $0.2 million, net, partially offset by lower outside services expenses and professional fees of $0.5 million.

Depreciation, Amortization, Taxes and Other decreased $2.8 million in 2006 compared to 2005, due to lower amortization on regulatory assets and lower utility plant depreciation rates resulting from the New Hampshire rate settlement, partially offset by increased depreciation on utility plant additions and higher property and payroll taxes.

Interest Expense, Net increased $1.1 million in 2006 compared to 2005 due to higher borrowings and interest rates compared to last year.

Usource, our non-regulated energy brokering business, recorded revenues of $2.4 million in 2006, an increase of $0.4 million over 2005. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource. The Company will also realize future fees estimated at the end of December 2006 of $6.0 million from executed energy supply term contracts running from 2007 through 2011.

The Company's Net Income was $8.4 million for 2005, an increase of $0.4 million, or 4.8%, compared to 2004. Earnings per common share were $1.51 for 2005, an increase of $0.06 per share compared with earnings of $1.45 per share for 2004. Compared to 2004, earnings for 2005 reflect higher electric sales, driven by customer growth and hotter summer weather in 2005, and higher gas sales reflecting a new contract with a large industrial customer.

In 2006, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2007 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

Per Share Data	2006	2005	2004
Earnings per Common Share	**$1.41**	$1.51	$1.45
Annual Dividend	**$1.38**	$1.38	$1.38

A more detailed discussion of the Company's 2006 results of operations and a year-to-year comparison of changes in financial position are presented below.

Balance Sheet

The Company's investment in Net Utility Plant increased by $18.5 million in 2006 compared to 2005. This increase was due to capital expenditures related to UES' and FG&E's electric and gas distribution systems and expenditures of approximately $7.3 million for the Company's Advanced Metering Infrastructure (AMI) project. AMI involves the integration of communication technology with metering technology to facilitate two-way communication between the utility and customer equipment. This technology is designed to provide more frequent, time-based metering information, enabling the recording and retrieval of interval metering data on at least an hourly basis.

Regulatory Assets increased $19.1 million in 2006 compared to 2005, primarily reflecting the recording of Regulatory Assets for Retirement Benefit Obligations in accordance with newly issued Federal Accounting Standards Board (FASB) Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158) (See Note 8) and the recording of a Regulatory Asset for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts (See Note 5), partially offset by a decrease in Regulatory Assets related to current year cost recoveries.

Long-Term Debt increased $14.7 million in 2006 compared to 2005 reflecting the issuance and sale on September 26, 2006 by UES of $15.0 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement.

Deferred Income Taxes decreased $17.8 million in 2006 compared to 2005 primarily reflecting the recording of deferred tax assets related to Retirement Benefit Obligations, discussed below.

Retirement Benefit Obligations increased $38.4 million in 2006 compared to 2005 primarily reflecting the recording of pension, PBOP and SERP obligations.

Environmental Obligations increased $12.0 million in 2006 compared to 2005 reflecting the recording of a liability for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, discussed above.

Sales

Kilowatt-hour Sales—The following table details total kWh sales for the last three years by major customer class:

kWh Sales (millions)

				2006 vs. 2005		2005 vs. 2004	
	2006	**2005**	**2004**	**Change**	**Change %**	**Change**	**Change %**
Residential	**672.2**	688.3	652.8	(16.1)	(2.3%)	35.5	5.4%
Commercial / Industrial	**1,079.3**	1,102.1	1,089.3	(22.8)	(2.1%)	12.8	1.2%
Total	**1,751.5**	1,790.4	1,742.1	(38.9)	(2.2%)	48.3	2.8%

Unitil's total kWh sales decreased 2.2% in 2006 compared to 2005. This decrease reflects a decline in average energy usage per customer, primarily due to significantly milder weather. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, resulting in lower consumption of electricity for heating related purposes. During the summer of 2006 the weather in the Company's service territories was approximately 11% cooler than in the same period for 2005, resulting in lower consumption of electricity for air conditioning purposes.

Unitil's total kWh sales increased 2.8% in 2005 compared to 2004. This increase reflects growth in sales to residential and commercial customers primarily due to hotter summer weather and an increase in the number of customers served in 2005 than in 2004.

Therm Sales—The following table details total firm therm sales for the last three years, by major customer class:

Firm Therm Sales (millions)

				2006 vs. 2005		2005 vs. 2004	
	2006	**2005**	**2004**	**Change**	**Change %**	**Change**	**Change %**
Residential	**9.8**	11.0	11.3	(1.2)	(10.9%)	(0.3)	(2.7%)
Commercial / Industrial	**16.6**	13.3	11.8	3.3	24.8%	1.5	12.7%
Total	**26.4**	24.3	23.1	2.1	8.6%	1.2	5.2%

Unitil's total firm therm sales of natural gas increased 8.6% in 2006 compared to 2005, due to a new gas transportation sales contract with a large industrial customer. Sales to residential customers decreased 10.9% in 2006 compared to 2005 due to a milder winter heating season in 2006 compared to the prior year.

Sales to C&I customers increased 24.8% in 2006 compared to 2005. Absent the sales from the new contract, discussed above, sales to C&I customers were 10.4% lower in 2006 compared to 2005 primarily due to a milder winter heating season. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, and the region as a whole experienced a record warm winter heating season.

In 2005, total firm therm sales of natural gas increased 5.2% compared to 2004, due to the new sales contract with a large industrial customer, discussed above. Sales to residential customers decreased 2.7% in 2005 compared to 2004 due to a milder winter heating season in 2005 compared to the prior year. Sales to C&I customers increased 12.7% in 2005 compared to 2004. Absent the sales from the new contract discussed above, sales to C&I customers were 3.4% lower in 2005 compared to 2004 due to lower natural gas usage by our largest customers.

Utility Revenues and Margin

Electric Operating Revenues—The following table details total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenues and Sales Margin (millions)

				2006 vs. 2005		2005 vs. 2004	
	2006	**2005**	**2004**	**$ Change**	**% Change[1]**	**$ Change**	**% Change[1]**
Electric Operating Revenue:							
Residential	**$102.6**	$ 82.2	$ 75.7	$20.4	10.3%	$ 6.5	3.5%
Commercial / Industrial	**122.6**	115.1	108.2	7.5	3.8%	6.9	3.8%
Total Electric Operating Revenue	**$225.2**	$197.3	$183.9	$27.9	14.1%	$13.4	7.3%
Cost of Electric Sales:							
Purchased Electricity	**$167.3**	$138.1	$125.9	$29.2	14.8%	$12.2	6.7%
Conservation & Load Management	**3.6**	3.8	3.5	(0.2)	(0.1%)	0.3	0.1%
Electric Sales Margin	**$ 54.3**	$ 55.4	$ 54.5	$ (1.1)	(0.6%)	$ 0.9	0.5%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues increased by $27.9 million, or 14.1%, in 2006 compared to 2005. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in 2006 reflects higher Purchased Electricity costs of $29.2 million, offset by lower sales margin of $1.1 million and lower C&LM revenues of $0.2 million.

Purchased Electricity and C&LM revenues increased a net $29.0 million, or 14.7%, of Total Electric Operating Revenues in 2006 compared to 2005, reflecting higher electric commodity prices. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin was lower by $1.1 million in 2006 compared to 2005, reflecting a decrease in revenue of $3.2 million related to the expiration of the Seabrook Amortization Surcharge (SAS) in late 2005. This decrease in SAS revenue is largely matched with a corresponding decrease in amortization expenses on Regulatory Assets, and therefore has no material impact on net income (see discussion on Depreciation and Amortization below). Absent the decrease in SAS revenues, electric sales margin increased $2.1 million in 2006 compared to 2005. The higher sales margin in 2006 primarily reflects the

Company's recently approved base rate increase in New Hampshire of $2.7 million, partially offset by lower sales margin of $0.6 million resulting from a decline in average energy usage per customer, primarily due to significantly milder weather.

In 2005, Total Electric Operating Revenues increased by $13.4 million, or 7.3%, compared to 2004. The net increase in Total Electric Operating Revenues in 2005 reflects higher Purchased Electricity costs of $12.2 million and higher C&LM revenues of $0.3 million and higher sales margin of $0.9 million. Purchased Electricity and C&LM revenues increased a combined $12.5 million, or 6.8%, of Total Electric Operating Revenues in 2005 compared to 2004, reflecting higher electricity unit sales and higher electric commodity prices and increased spending on energy efficiency programs. Electric sales margin increased by $0.9 million in 2005 compared to 2004, primarily reflecting increased kWh unit sales and higher base rates, partially offset by the expiration of the SAS in 2005, as discussed above.

Gas Operating Revenues—The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenues and Sales Margin (millions)

				2006 vs. 2005		2005 vs. 2004	
	2006	**2005**	**2004**	**$ Change**	**% Change[1]**	**$ Change**	**% Change[1]**
Gas Operating Revenue:							
Residential	**$18.0**	$19.0	$16.3	$(1.0)	(3.1%)	$ 2.7	9.4%
Commercial / Industrial	**12.9**	13.7	12.3	(0.8)	(2.4%)	1.4	4.9%
Total Firm Gas Revenue	**$30.9**	$32.7	$28.6	$(1.8)	(5.5%)	$ 4.1	14.3%
Interruptible Gas Revenue	**2.4**	0.1	0.1	2.3	7.0%	—	—
Total Gas Operating Revenue	**33.3**	32.8	28.7	0.5	1.5%	4.1	14.3%
Cost of Gas Sales:							
Purchased Gas	**$22.4**	$21.2	$17.5	$ 1.2	3.7%	$ 3.7	12.9%
Conservation & Load Management	**0.2**	0.3	0.5	(0.1)	(0.4%)	(0.2)	(0.7%)
Gas Sales Margin	**$10.7**	$11.3	$10.7	$(0.6)	(1.8%)	$ 0.6	2.1%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $0.5 million, or 1.5%, in 2006 compared to 2005. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in 2006 reflects higher Purchased Gas costs of $1.2 million, offset by lower sales margin of $0.6 million and lower C&LM revenues of $0.1 million.

Purchased Gas and C&LM revenues increased a net $1.1 million, or 3.3%, of Total Gas Operating Revenues in 2006 compared to 2005, reflecting higher gas commodity prices and higher unit sales during those periods. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin for 2006 decreased $0.6 million compared to 2005. In the third quarter of 2005, the Company entered into a new gas sales contract with a large industrial customer which resulted in an increase in gas sales margin of $0.5 million in 2006 compared to 2005. Prior to the fourth quarter of 2006, the Company had recorded revenue from this contract on a reduced basis, pending the resolution of a margin sharing proceeding by the MDTE. As part of a settlement agreement with the MDTE for FG&E's gas division, the Company is allowed to earn the full margin associated with this contract. As a result, the

Company recognized $0.2 million of gas margin in the fourth quarter of 2006 which had been deferred pending a decision by the MDTE. Absent the gas sales margin from this contract, gas sales margin decreased $1.1 million in 2006 compared to 2005. This decline in gas sales margin was due to lower therm sales, which, absent the sales from the new contract were 10.8% lower in 2006 compared to 2005. The lower gas sales were primarily due to a milder winter heating season. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, reflecting a record warm winter heating season.

In 2005, Total Gas Operating Revenues increased $4.1 million, or 14.3%, compared to 2004. The net increase in Total Gas Operating Revenues in 2005 reflects higher Purchased Gas costs of $3.7 million and higher sales margin of $0.6 million, partially offset by lower C&LM revenues of $0.2 million.

Purchased Gas and C&LM revenues increased a net $3.5 million, or 12.2%, of Total Gas Operating Revenues in 2005 compared to 2004, reflecting higher gas commodity prices, higher unit sales and lower spending on energy efficiency programs that were implemented during those periods. Gas sales margin for 2005 increased $0.6 million compared to 2004. This increase in gas sales margin was attributable to an increase in firm therm sales and higher rates authorized by regulators to recover certain post retirement benefit costs.

Non-regulated Revenues

Total Other Revenue increased $0.4 million in 2006 compared to 2005 and $0.4 million in 2005 compared to 2004. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource. The Company will also realize future fees, estimated at December 31, 2006, of $6.0 million from executed energy supply contracts running 2007 through 2011.

The following table details total Other Revenue for the last three years:

Other Revenue (millions)

				2006 vs. 2005		2005 vs. 2004	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Usource	**$2.4**	$2.0	$1.6	$0.4	20.0%	$0.4	25.0%
Total Other Revenue	**$2.4**	$2.0	$1.6	$0.4	20.0%	$0.4	25.0%

Operating Expenses

Purchased Electricity—Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity increased $29.2 million, or 21.1%, in 2006 compared to 2005, reflecting higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not affect earnings.

In 2005, Purchased Electricity expenses increased $12.2 million, or 9.7%, compared to 2004 due primarily to higher electric commodity prices.

Purchased Gas—Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $1.2 million, or 5.6%, in 2006 compared to 2005. The increase in Purchased Gas is attributable to increased therm sales and higher gas commodity costs. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

In 2005, Purchased Gas increased by $3.7 million, or 21.4%, compared to 2004, reflecting increased therm sales and higher natural gas commodity costs.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's non-regulated business activities. Total O&M expense increased $1.2 million, or 3.3%, in 2006 compared to 2005. This increase reflects higher retiree and employee benefit costs of $0.8 million, driven by higher medical claims, higher salaries and compensation expenses of $0.7 million, due to normal annual increases, and an increase in all other operating expenses of $0.2 million, net, offset by lower outside services expenses and professional fees of $0.5 million.

In 2005, total O&M expense increased $1.2 million, or 5.2%, compared to 2004, reflecting higher salaries and compensation expenses of $0.6 million, higher retiree and employee benefit costs of $0.5 million, higher audit fees of $0.2 million, higher utility operating and maintenance expenses $0.1 million and higher bad debt expenses of $0.1 million, partially offset by lower administrative and general expenses of $0.3 million.

Conservation & Load Management—Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total Conservation & Load Management expenses decreased slightly, by $0.4 million, in 2006 compared to 2005. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total Conservation & Load Management expenses increased $0.1 million, in 2005 compared to 2004.

Depreciation and Amortization—Depreciation and Amortization expense decreased $3.1 million, or 16.0%, in 2006 compared to 2005, reflecting lower amortization on regulatory assets, including Seabrook Station, $3.3 million, and lower depreciation rates on utility plant resulting from the NHPUC's order in UES' base rate case, $0.6 million, partially offset by depreciation on utility plant additions, $0.8 million. The Company's regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005. The lower amortization on Seabrook Station is largely matched with a corresponding decrease in SAS revenues and therefore has no material impact on net income (see discussion of Electric Operating Revenues above).

In 2005, Depreciation and Amortization expense increased $0.3 million, or 1.6%, compared to 2004, reflecting higher depreciation on normal utility plant additions, partially offset by lower amortization in 2005 on the Company's regulatory assets related to its former abandoned property investment in Seabrook Station, discussed above.

Local Property and Other Taxes—Local Property and Other Taxes increased by $0.3 million, or 5.4%, in 2006 compared to 2005. This increase was due to higher local property tax rates on higher levels of utility plant in service and higher payroll taxes.

In 2005, Local Property and Other Taxes increased by less than $0.1 million, or 0.7% compared to 2004. This increase was due to higher local property tax rates on higher levels of utility plant in service.

Federal and State Income Taxes—Federal and State Income Taxes were essentially flat in 2006 compared to 2005 due to lower pre-tax operating income in 2006 compared to 2005 offset by a higher effective tax rate in 2006 related to the Company's former abandoned property investment in Seabrook Station, discussed above. Federal and State Income Taxes increased $0.1 million, or 1.6%, in 2005 compared to 2004 reflecting higher pre-tax operating income year over year.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) improved to income of $19,000 in 2006 compared to an expense of $147,000 in 2005 due to a gain on the sale of land in Massachusetts and timber harvest revenue recorded in New Hampshire. Other Non-operating expenses of $147,000 in 2005 were $46,000 lower compared to 2004 due to lower jobbing parts expenses and lower donations expenses.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's rate tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)	2006	2005	2004	2006 vs. 2005 Change	2005 vs. 2004 Change
Interest Expense					
Long-term Debt	**$ 9.5**	$ 8.4	$ 8.5	$ 1.1	$(0.1)
Short-term Debt	**1.5**	1.0	0.5	0.5	0.5
Regulatory Liabilities	**0.3**	0.2	0.1	0.1	0.1
Subtotal Interest Expense	**11.3**	9.6	9.1	1.7	0.5
Interest Income					
Regulatory Assets	**(3.1)**	(2.6)	(2.3)	(0.5)	(0.3)
AFUDC and Other	**(0.4)**	(0.2)	—	(0.2)	(0.2)
Subtotal Interest Income	**(3.5)**	(2.8)	(2.3)	(0.7)	(0.5)
Total Interest Expense, net	**$ 7.8**	$ 6.8	$ 6.8	$ 1.0	$ —

In 2006, Total Interest Expense, Net increased by $1.0 million compared to 2005. Interest expense on long-term borrowings increased due to the issuance of new fixed rate long-term debt. Unitil's New Hampshire subsidiary, UES, issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. In December 2005, Unitil's Massachusetts utility subsidiary, FG&E, issued $15 million of unsecured long-term notes to institutional investors at an interest rate of 5.90%. The proceeds from these long-term financings were used principally to finance utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. Interest expense on short-term debt increased compared to 2005 primarily due to higher variable short-term interest rates. These increases in interest expense were partially offset by an increase in interest income due to higher carrying charges on regulatory assets.

In 2005, Interest Expense, Net, increased by less than $0.1 million compared to 2004. The net change in Interest Expense, Net, reflects higher variable interest costs on short-term debt, partially offset by higher interest income from carrying charges on regulatory assets. A rise in bank borrowing rates and average daily bank borrowings during 2005 drove Interest Expense on short-term debt.

LIQUIDITY, COMMITMENTS AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. At December 31, 2006, Unitil had an aggregate of $40.0 million in unsecured revolving lines of credit with three banks. On January 1, 2007, Unitil's bank lines of credit increased to $41.0 million with the same three banks. The Company anticipates that it will be able to secure renewal or replacement of some or all of its revolving lines of credit, in accordance with projected requirements. The Company had short-term debt outstanding through bank borrowings of $26.0 million and $18.7 million at December 31, 2006 and December 31, 2005, respectively. In addition, Unitil had approximately $4.6 million in cash at December 31, 2006. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets.

The maximum amount of short-term borrowings that may be incurred by Unitil and its subsidiaries has been subject to periodic approval by the SEC under the PUHCA and state regulators of the Company's retail distribution utilities, UES and FG&E. However, in 2005 the PUHCA was repealed. Under the Energy Policy Act of 2005, many regulatory oversight responsibilities of the SEC prior to the repeal of the PUHCA were transferred to the FERC. The FERC's transition rule permits Unitil and its subsidiaries to rely on outstanding SEC orders issued under the PUHCA , including an order related to Unitil's cash pooling and loan arrangement and certain maximum borrowing authorizations to be extended through December 31, 2007. At December 31, 2006, Unitil had regulatory authorization to incur total short-term bank borrowings up to a maximum of $55 million, and UES and FG&E had regulatory authorizations to borrow up to a maximum of $16 million and $35 million, respectively. In 2006, UES and FG&E had average short-term debt outstanding of $9.8 million and $20.8 million, respectively.

Unitil and its subsidiaries are individually and collectively members of the Unitil Cash Pool. The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool Agreement allows an efficient exchange of cash among Unitil and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on Unitil's actual interest costs from its banks under the revolving lines of credit. At December 31, 2006, all Unitil subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

On September 26, 2006, UES issued and sold $15.0 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement (see Note 3). The proceeds from this long-term financing were used principally to permanently finance utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. In December 2005, FG&E issued and sold $15.0 million of 5.90% unsecured long-term notes under a debenture note structure (see Note 3). The proceeds were utilized to repay outstanding short-term indebtedness of FG&E. The Company expects to continue to be able to satisfy its external financing needs by utilizing additional short-term bank borrowings and to periodically replace short-term debt with long-term financings.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2006.

		Payments Due by Period			
Significant Contractual Obligations (000's) as of December 31, 2006	**Total**	**2007**	**2008-2009**	**2010-2011**	**2012 & Beyond**
Long-term Debt	$140,364	$ 336	$ 758	$ 889	$138,381
Capital Lease	442	233	207	2	—
Operating Leases	2,820	456	909	808	647
Power Supply Contract Obligations—MA	49,987	8,001	16,396	16,912	8,678
Power Supply Contract Obligations—NH	42,571	11,870	21,677	5,226	3,798
Gas Supply Contracts	16,128	12,967	1,855	1,216	90
Total Contractual Cash Obligations	**$252,312**	**$33,863**	**$41,802**	**$25,053**	**$151,594**

The Company has material energy supply commitments that are discussed in Note 4. Cash outlays for the purchase of electricity and natural gas to serve our customers are subject to full recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over collected cash over subsequent 6-12 month periods.

The Company also provides limited guarantees on certain electric supply contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2006 there are $7.0 million of guarantees outstanding and these guarantees extend through October 8, 2008.

Benefit Plan Funding

In 2006 the Company and its subsidiaries made cash contributions to its pension plan in the amount of $2.5 million. In 2006 and 2005, the Company and its subsidiaries contributed approximately $2.2 million and $2.5 million, respectively to the Voluntary Employee Benefit Trusts (VEBT) and expects to continue to make contributions to the VEBT's in future years in amounts consistent with the amounts recovered in retail distribution utility rates for these other postretirement benefit costs.

Off-Balance Sheet Arrangements

The Company does not currently use, and is not dependent on the use of off-balance sheet financing arrangements, such as securitization of receivables, or obtaining access to assets or cash through special purpose entities or variable interest entities. The Company does have an operating lease agreement with a major financial institution. The operating lease is used to finance the Company's utility vehicles. (See Note 3).

Cash Flows

	2006	2005
Cash Provided by Operating Activities (000's)	**$20,373**	$24,076

Cash Provided by Operating Activities—Cash Provided by Operating Activities was $20.4 million in 2006, a decrease of $3.7 million compared to 2005. Sources of cash from Net Income were lower by $0.5 million compared to last year and sources of cash from Depreciation and Amortization were lower by approximately $3.1 million in 2006 compared to 2005, primarily due to the lower amortization of the Seabrook regulatory asset. Working capital related cash flows decreased $6.0 million in 2006 compared to 2005. Major uses of cash working capital were due to: Accrued Revenue, which decreased by $5.7 million year over year principally due to the recording of a temporary rate deferral in 2006 that will be fully collected before the end of 2007 and Accounts Payable, which decreased by $5.1 million compared to last year reflecting a higher level of funding of energy costs and other operating expenses in 2006. Major sources of cash working capital were due to Accounts Receivable collection, which provided $6.6 million over 2005 due to improved cash remittance activity. Sources of cash related to Deferred Restructuring Costs increased by $5.4 million in 2006 as compared to 2005, reflecting improvement in net cash flows for the collection of deferred costs related to utility industry restructuring. All other changes in cash flows from operating activities were a net increase of $0.5 million in sources of cash in 2006 compared to 2005.

	2006	2005
Cash (Used in) Investing Activities (000's)	**$(33,642)**	$(24,367)

Cash (Used in) Investing Activities—Cash (Used in) Investing Activities increased by $9.3 million in 2006 compared to 2005. Cash used in investing activities is primarily for capital expenditures related to UES' and FG&E's electric and gas distribution systems. Capital expenditures are projected to be $32.4 million in 2007, reflecting normal electric and gas utility system additions and expenditures for the last phase of the Company's AMI project, discussed above.

	2006	2005
Cash Provided by (Used in) Financing Activities (000's)	**$14,618**	$ 466

Cash Provided by (Used in) Financing Activities—Cash Provided by (Used in) Financing Activities was $14.6 million in 2006. Cash was provided by financing proceeds from the issuance and sale of $15.0 million of First Mortgage Bonds by UES; short-term borrowings of $7.3 million from Unitil's banks; and the issuance and sale of $1.0 million of Unitil's Common Stock. Cash Used in Financing Activities reflects $7.9 million in Common and Preferred dividends paid; retirement of $0.3 million of preferred stock; and to repay long-term debt and capital leasing obligations, amounting to $0.5 million.

On September 26, 2006, UES completed the sale of $15.0 million of Series O First Mortgage Bonds through a private placement to institutional investors. The bonds have a term of 30 years and a coupon rate of 6.32%.

In 2005, Cash Provided by (Used in) Financing activities was $0.5 million. Cash was provided by financing proceeds from the issuance and sale of $15.0 million of long-term notes by FG&E and $1.0 million of Common Stock. Cash Used in Financing Activities included the payment of dividends amounting to $7.8 million and repayment of $7.0 million of short-term bank indebtedness.

On December 21, 2005, FG&E completed the sale of $15.0 million of unsecured long-term notes through a private placement to institutional investors. The notes have a term of 25 years and a coupon rate of 5.90%.

FINANCIAL COVENANTS AND RESTRICTIONS

The agreements under which the long-term debt of the retail distribution utilities, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Indenture Agreements further require that if UES defaults on any FMB securities, it would constitute a default for all UES FMB securities. The default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

FG&E utilizes a debenture structure of long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Indenture Agreements, FG&E's agreements require that if FG&E defaults on any long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

In addition, the UES and FG&E long-term debt instruments and agreements contain certain restrictions on the payment of common dividends from Retained Earnings. On December 31, 2006, UES and FG&E had unrestricted Retained Earnings of $14.8 million and $7.2 million, respectively, available for the payment of common dividends (See Note 3.) UES and FG&E pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil shareholders.

Unitil Corporation has no long-term debt outstanding. The long-term debt and preferred stock of UES and FG&E are privately held, and the Company does not issue commercial paper. For these reasons, these securities of Unitil and its subsidiaries are not publicly rated.

DIVIDENDS

Unitil's annualized common dividend was $1.38 per common share in 2006, 2005 and 2004. Unitil's dividend policy is reviewed periodically by the Board of Directors. Unitil has maintained an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2007 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

REGULATORY MATTERS

Overview—Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on an historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, all of Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the providers of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next four to six years, is $126.1 million as of December 31, 2006 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet (see Regulatory Assets table in Note 1.) Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E—Electric Division—FG&E provides electric distribution service to customers under unbundled distribution rates approved by the MDTE. Its current retail electric distribution rates were approved by the MDTE in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of December 31, 2006, approximately 53 percent of FG&E's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large C&I customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $33.3 million at December 31, 2006, and $34.4 million at December 31, 2005, and is expected to be recovered in FG&E's rates over the next four to six years. In addition, as of December 31, 2006, FG&E had recorded on its balance sheet $50.0 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates (See Note 1.)

On March 7, 2006, the MDTE approved FG&E's 2003 and 2004 annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. FG&E's 2005 and 2006 filings, which are subject to investigation, are pending. The Company expects that these filings will be approved without material changes or adjustments.

FG&E—Gas Division—FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDTE in 2002. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On January 26, 2007, the MDTE approved a rate Settlement Agreement (Settlement) which FG&E and the Attorney General of Massachusetts had signed and filed with the MDTE for FG&E's Gas Division on November 29, 2006. Under the Settlement, FG&E will phase-in gas distribution rate changes with an initial rate increase of $1.2 million as of February 1, 2007, and an additional $1.0 million increase on November 1, 2007. The Settlement also includes agreement on several other rate matters and service quality performance measures for the company's gas division in the areas of safety, customer service and satisfaction.

On September 7, 2006, the MDTE issued an order allowing FG&E to recover its actual gas and electric supply-related bad debt effective December 1, 2005. Prior to this final approval, FG&E had recovered supply related bad debt based on a fixed rate formula that was resulting in a significant underrecovery of these costs. On September 27, 2006, the Attorney General filed a Petition for Appeal with the Massachusetts Supreme Judicial Court seeking to set aside the MDTE's order of September 7, 2006. FG&E intends to support the MDTE's order but the Company cannot predict the outcome of the Attorney General's appeal at this time.

UES—UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were approved by the NHPUC in 2006 under the Settlement Agreement discussed below. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of December 31, 2006, approximately 80 percent of UES' electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large C&I customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery, including certain charges that are subject to annual or periodic reconciliation or future review. As of December 31, 2006, UES had recorded on its balance sheets $42.6 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately four years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 17, 2006, UES made its third annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2006, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. The NHPUC approved the filing on April 28, 2006.

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement (Agreement) resolving all issues in its electric distribution base rate case filed in November, 2005. The terms of the Agreement provide for an increase in base distribution rates of $2.3 million annually, effective as of January 1, 2006. Additionally, the Agreement authorizes two step increases in base distribution rates, related to utility plant additions in 2006, of approximately $0.4 million and $0.1 million annually, effective as of November 1, 2006 and May 1, 2007, respectively. Also, the Agreement provides for the recovery of approximately $0.3 million annually of supply-related operating and administrative costs through default energy service rates and a reduction of approximately $0.6 million in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives. The stipulated rate of return under the settlement is 8.70%, including a return on equity of 9.67%. The Agreement also authorizes a temporary rate surcharge for recovery of certain rate case expenses and recoupment of the authorized distribution rate increase from January through October 2006.

FERC—Wholesale Power Markets—FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the Regional Transmission Organization (RTO) in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England are performed on a regional basis. The Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDTE and NHPUC.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2006, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—FG&E continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary closure of the site. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E has recovered the environmental response costs incurred at this former MGP site in gas rates pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition FG&E has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

FG&E is in the process of developing long range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2006 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of the site. A corresponding regulatory asset was recorded to reflect the future rate recovery for these costs. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

The Company's ultimate liability for future environmental remediation costs may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

EMPLOYEES AND EMPLOYEE RELATIONS

As of December 31, 2006, the Company and its subsidiaries had 304 employees. The Company considers it relationships with employees to be good and has not experienced any major labor disruptions.

There are approximately 100 employees represented by labor unions. These employees are covered by collective bargaining agreements, which expire May 31, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet. Generally, the Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. Generally, the Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. The Company must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, the its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts—The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Retirement Benefit Obligations—The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company.

In September 2006, the FASB issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates. See Note 8 for a table showing the incremental effect of applying SFAS No. 158 on individual line items of the Company's Consolidated Balance Sheet at December 31, 2006.

The Company accounts for its pension and postretirement benefits in accordance with SFAS No. 158, SFAS No. 87 and SFAS No. 106. In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on these significant assumptions.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements. See Note 8.

Pension income is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets of 8.50%, 8.50% and 8.75% for 2006, 2005 and 2004, respectively. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2006. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2006, 2005 and 2004 was $2,609,128, $2,391,745 and $1,981,667, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2006, 2005 and 2004 would have been $2,759,208, $2,225,181 and $2,119,667 respectively.

The discount rate that is utilized in determining future pension obligations is based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate used for 2006 was 5.50%. For the period January 1, 2005 through May 31, 2005, the discount rate used was 6.50%. In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the defined benefit pension plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%. The discount rate used for the 2004 fiscal year was 6.50%. For 2006, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Pension Cost. Similarly, for 2005 and 2004, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000. The compensation cost increase assumption used for 2006, 2005 and 2004 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the Plan.

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) which is the authoritative pronouncement on accounting for and reporting income taxes. In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise's financial statements. FIN 48 prescribes a "more-likely-than-not" recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 applies to all tax positions related to income taxes subject to FAS 109. This includes tax positions considered to be "routine" as well as those with a high degree of uncertainty such as tax-advantaged transactions. FIN 48 effectively amends FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5), such that all references to income taxes in SFAS No. 5 have been deleted and FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. FIN 48 creates a single model to address accounting for uncertainty in tax positions. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition, and classification and the cumulative affect of adopting FIN 48 may be recorded as an adjustment to retained earnings.

FIN 48 requires disclosures of items and amounts that would affect the Company's effective tax rate in its statement of earnings. FIN 48 also provides guidance on disclosures for interim reporting periods for accounting for income taxes, interest and penalties. The Company will adopt FIN 48 as of January 1, 2007, as required. The Company does not expect that the adoption of FIN 48 will have a significant impact on the Company's financial position and results of operations.

Depreciation—Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2006, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements' in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 7, "Income Taxes," Note 4, "Energy Supply," Note 8, "Benefit Plans," and Note 5, "Commitment and Contingencies," to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please also refer to Item 1A. "Risk Factors".

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 5.5%, 3.8% and 1.9% during 2006, 2005 and 2004, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Item 8.   Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Unitil Corporation and subsidiaries as of December 31, 2006 and December 31, 2005, and the related consolidated statements of earnings, cash flows and changes in common stock equity for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Unitil Corporation and subsidiaries as of December 31, 2006 and December 31, 2005 and the consolidated results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Unitil Corporation's internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 2, 2007 expressed an opinion on management's assessment of internal control over financial reporting and a unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ Vitale, Caturano & Co. Ltd.

Boston, Massachusetts
February 2, 2007

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated statements of earnings, cash flows and changes in common stock equity of Unitil Corporation and subsidiaries for the year ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of Unitil Corporation and subsidiaries' operations and their cash flows for the year ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Unitil Corporation's internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2005 (not separately included herein), expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Boston, Massachusetts
February 17, 2005

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that Unitil Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission* (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Unitil Corporation and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in the Internal Control-Integrated Framework issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and consolidated statements of capitalization of Unitil Corporation and subsidiaries as of December 31, 2006, and the related consolidated statements of earnings, cash flows and changes in common stock equity for the years then ended, and our report dated February 2, 2007, expressed an unqualified opinion on those consolidated financial statements.

/s/ Vitale, Caturano & Co. Ltd.

Boston, Massachusetts
February 2, 2007

CONSOLIDATED STATEMENTS OF EARNINGS

(000's, except common shares and per share data)

Year Ended December 31,	2006	2005	2004
Operating Revenues:			
Electric	**$ 225,154**	$ 197,338	$ 183,889
Gas	**33,271**	32,768	28,685
Other	**2,436**	2,039	1,563
Total Operating Revenues	**260,861**	232,145	214,137
Operating Expenses:			
Purchased Electricity	**167,333**	138,134	125,940
Purchased Gas	**22,405**	21,225	17,486
Operation and Maintenance	**25,680**	24,514	23,297
Conservation & Load Management	**3,752**	4,115	4,003
Depreciation and Amortization	**16,069**	19,123	18,830
Provisions for Taxes:			
Local Property and Other	**5,501**	5,218	5,182
Federal and State Income	**4,266**	4,275	4,206
Total Operating Expenses	**245,006**	216,604	198,944
Operating Income	**15,855**	15,541	15,193
Other Non-Operating Expenses (Income)	**(19)**	147	193
Income Before Interest Expense	**15,874**	15,394	15,000
Interest Expense, net	**7,841**	6,841	6,774
Net Income	**8,033**	8,553	8,226
Less Dividends on Preferred Stock	**133**	156	215
Earnings Applicable to Common Shareholders	**$ 7,900**	$ 8,397	$ 8,011
Average Common Shares Outstanding—Basic	**5,597,465**	5,551,420	5,509,321
Average Common Shares Outstanding—Diluted	**5,611,734**	5,567,718	5,524,835
Earnings per Common Share—Basic and Diluted	**$ 1.41**	$ 1.51	$ 1.45

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (*000's*)

ASSETS

December 31,	2006	2005
Utility Plant:		
Electric	**$250,304**	$234,153
Gas	**63,428**	58,675
Common	**25,220**	26,515
Construction Work in Progress	**14,047**	5,624
Utility Plant	**352,999**	324,967
Less: Accumulated Depreciation	**121,191**	111,646
Net Utility Plant	**231,808**	213,321
Current Assets:		
Cash	**4,556**	3,207
Accounts Receivable—(Net of Allowance for Doubtful Accounts of $1,737 and $470)	**22,546**	23,631
Accrued Revenue	**13,766**	8,905
Material and Supplies	**4,536**	3,675
Prepayments and Other	**1,293**	1,963
Total Current Assets	**46,697**	41,381
Noncurrent Assets:		
Regulatory Assets	**198,828**	179,719
Prepaid Pension	**—**	11,099
Debt Issuance Costs, net	**2,560**	2,343
Other Noncurrent Assets	**3,534**	2,218
Total Noncurrent Assets	**204,922**	195,379
TOTAL	**$483,427**	$450,081

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (cont.) *(000's)*

CAPITALIZATION AND LIABILITIES

December 31,	2006	2005
Capitalization:		
Common Stock Equity	**$ 97,775**	$ 96,283
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225
Preferred Stock, Redeemable, Cumulative	**1,858**	2,102
Long-Term Debt, Less Current Portion	**140,028**	125,365
Total Capitalization	**239,886**	223,975
Current Liabilities:		
Long-Term Debt, Current Portion	**336**	308
Capitalized Leases, Current Portion	**233**	261
Accounts Payable	**19,813**	20,600
Short-Term Debt	**26,000**	18,700
Taxes Payable	**888**	—
Interest and Dividends Payable	**1,646**	1,403
Other Current Liabilities	**4,554**	4,708
Total Current Liabilities	**53,470**	45,980
Deferred Income Taxes	**34,526**	52,297
Noncurrent Liabilities:		
Power Supply Contract Obligations	**92,558**	114,906
Retirement Benefit Obligations	**49,663**	11,289
Environmental Obligations	**12,000**	—
Capitalized Leases, Less Current Portion	**209**	324
Other Noncurrent Liabilities	**1,115**	1,310
Total Noncurrent Liabilities	**155,545**	127,829
TOTAL	**$483,427**	$450,081

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(000's except number of shares and par value)

December 31,	2006	2005
Common Stock Equity		
Common Stock, No Par Value (Authorized—8,000,000 shares; Outstanding—5,650,263 and 5,595,523 shares)	**$ 61,827**	$ 60,826
Stock Compensation Plans	**1,661**	1,310
Retained Earnings	**34,287**	34,147
Total Common Stock Equity	**97,775**	96,283
Preferred Stock		
UES Preferred Stock, Non-Redeemable, Non-Cumulative:		
6.00% Series, $100 Par Value	**225**	225
FG&E Preferred Stock, Redeemable, Cumulative:		
5.125% Series, $100 Par Value	**874**	892
8.00% Series, $100 Par Value	**984**	1,210
Total Preferred Stock	**2,083**	2,327
Long-Term Debt		
UES First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15,000**	15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000
6.32% Series, Due September 15, 2036	**15,000**	—
FG&E Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19,000**	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000
6.79% Notes, Due October 15, 2025	**10,000**	10,000
5.90% Notes, Due December 15, 2030	**15,000**	15,000
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**5,364**	5,673
Total Long-Term Debt	**140,364**	125,673
Less: Current Portion	**336**	308
Total Long-Term Debt, Less Current Portion	**140,028**	125,365
Total Capitalization	**$239,886**	$223,975

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS (000's)

Year Ended December 31,	2006	2005	2004
Operating Activities:			
Net Income	**$ 8,033**	$ 8,553	$ 8,226
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**16,069**	19,123	18,830
Deferred Tax (Benefit) Provision	**481**	(240)	3,166
Changes in Current Assets and Liabilities:			
Accounts Receivable	**1,085**	(5,512)	(658)
Accrued Revenue	**(4,861)**	849	275
Accounts Payable	**(787)**	4,351	1,225
Taxes Payable	**888**	626	2,839
All Other Current Assets and Liabilities	**(86)**	1,386	5,597
Deferred Restructuring Charges	**1,129**	(4,223)	(5,820)
Other, net	**(1,578)**	(837)	(3,032)
Cash Provided by Operating Activities	**20,373**	24,076	30,648
Investing Activities:			
Property, Plant and Equipment Additions	**(33,642)**	(24,367)	(22,922)
Cash Used In Investing Activities	**(33,642)**	(24,367)	(22,922)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**7,300**	(6,975)	3,265
Issuance of Long-Term Debt	**15,000**	15,000	—
Repayment of Long-Term Debt	**(310)**	(286)	(3,264)
Retirement of Preferred Stock	**(243)**	(11)	(931)
Dividends Paid	**(7,908)**	(7,843)	(7,857)
Issuance of Common Stock	**1,001**	1,031	947
Repayment of Capital Lease Obligations	**(222)**	(450)	(620)
Cash Provided by (Used In) Financing Activities	**14,618**	466	(8,460)
Net Increase (Decrease) in Cash	**1,349**	175	(734)
Cash at Beginning of Year	**3,207**	3,032	3,766
Cash at End of Year	**$ 4,556**	$ 3,207	$ 3,032
Supplemental Information:			
Interest Paid	**$ 10,690**	$ 9,455	$ 9,052
Income Taxes Paid	**$ 3,101**	$ 4,544	$ 990

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF
CHANGES IN COMMON STOCK EQUITY

(000's except number of shares)

	Common Shares	Stock Compensation Plans	Retained Earnings	Total
Balance at January 1, 2004	$58,848	$ 908	$33,049	**$92,805**
Net Income for 2004			8,226	**8,226**
Dividends on Preferred Shares			(215)	**(215)**
Dividends on Common Shares			(7,623)	**(7,623)**
Stock Compensation Plans		151		**151**
Issuance of 35,310 Common Shares	947			**947**
Balance at December 31, 2004	59,795	1,059	33,437	**94,291**
Net Income for 2005			8,553	**8,553**
Dividends on Preferred Shares			(156)	**(156)**
Dividends on Common Shares			(7,687)	**(7,687)**
Stock Compensation Plans		251		**251**
Issuance of 38,003 Common Shares	1,031			**1,031**
Balance at December 31, 2005	60,826	1,310	34,147	**96,283**
Net Income for 2006			8,033	**8,033**
Dividends on Preferred Shares			(133)	**(133)**
Dividends on Common Shares			(7,760)	**(7,760)**
Stock Compensation Plans		351		**351**
Issuance of 40,365 Common Shares	1,001			**1,001**
Balance at December 31, 2006	**$61,827**	**$1,661**	**$34,287**	**$97,775**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—In accordance with current accounting pronouncements, the Company's consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the Company-owned retail distribution utilities: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the Massachusetts Department of Telecommunications and Energy (MDTE) and UES is regulated by the New Hampshire Public Utilities Commission (NHPUC). Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or “regulatory assets” under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or “regulatory liabilities” under SFAS No. 71.

The Company’s principal regulatory assets and liabilities are detailed on the Company’s Consolidated Balance Sheet and a summary of the Company’s Regulatory Assets is provided below. Generally, the Company is currently receiving or being credited with a return on primarily all of its regulatory assets for which a cash outflow has been made. Generally, the Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company’s regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. The Company must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company’s consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

	December 31,	
Regulatory Assets consist of the following (millions)	**2006**	**2005**
Power Supply Buyout Obligations	**$ 92.6**	$114.9
Deferred Restructuring Costs	**31.0**	31.2
Generation-related Assets	**2.5**	3.3
Subtotal—Restructuring Related Items	**126.1**	149.4
Retirement Benefit Obligations	**37.1**	9.2
Income Taxes	**19.1**	17.5
Environmental Obligations	**13.0**	0.4
Other	**3.5**	3.2
Total Regulatory Assets	**$198.8**	$179.7

Massachusetts and New Hampshire have both passed utility industry restructuring legislation and the Company has filed and implemented its restructuring plans in both states. The Company is allowed to recover certain types of costs through ongoing assessments to be included in future retail rates. Based on the recovery mechanism that allows recovery of all of its stranded costs and deferred costs related to restructuring, the Company has recorded regulatory assets that it expects to fully recover in future periods. The Company expects to continue to meet the criteria for the application of SFAS No. 71 for the distribution portion of its assets and operations for the foreseeable future.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated subsidiaries will be subject to SFAS No. 71 for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. Financial instruments that subject the Company to credit risk concentrations consist of cash and cash equivalents and accounts receivable. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. The Company believes it is not exposed to any significant credit risk on cash. Under the Independent System Operator—New England (ISO-NE) Financial Assurance Policy (Policy), Unitil's affiliates UES, FG&E and Unitil Power are required to provide assurance of their ability to satisfy their obligations to ISO-NE. Under this Policy, Unitil's affiliates provide cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2006 and 2005, the Unitil affiliates had deposited $2.0 million and $1.5 million, respectively to satisfy their ISO-NE obligations.

Goodwill and Intangible Assets—The Company does not have any goodwill recorded on its balance sheet as of December 31, 2006. There are no significant intangible assets recorded by the Company at December 31, 2006. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

Off-Balance Sheet Arrangements—As of December 31, 2006, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases and, in the Company's opinion, the amount of these transactions is not material.

Investments and Trading Activities—During the year, the Company does invest in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for book accounting purposes.

Derivatives—The Company enters into wholesale electric and gas energy supply contracts to serve its customers. The Company's policy is to review each contract and determine whether they meet the criteria for classification as derivatives under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133) and / or FASB Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). As of December 31, 2006, the Company determined that none of its wholesale electric and gas energy supply contracts met the criteria for classification as a derivative instrument. Additionally, the Company may enter into interest rate hedging transactions with respect to existing indebtedness and anticipated debt offerings. As of December 31, 2006, the Company has not entered into any such transactions. However, should the Company enter into any such transactions in the future, its policy will be to review each transaction and determine whether it meets the criteria for classification as derivatives under SFAS No. 133 and / or SFAS No. 149.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition—Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts—The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Retirement Benefit Obligations—The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company.

In September 2006, the FASB issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates. See Note 8 for a table showing the incremental effect of applying SFAS No. 158 on individual line items of the Company's Consolidated Balance Sheet at December 31, 2006.

The Company accounts for its pension and postretirement benefits in accordance with SFAS No. 158, SFAS No. 87 and SFAS No. 106. In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on these significant assumptions.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements (See Note 8.)

Pension income is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets of 8.50%, 8.50% and 8.75% for 2006, 2005 and 2004, respectively. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment advisors. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2006. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2006, 2005 and 2004 was $2,609,128, $2,391,745 and $1,981,667, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2006, 2005 and 2004 would have been $2,759,208, $2,225,181 and $2,119,667 respectively.

The discount rate that is utilized in determining future pension obligations is based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate used for 2006 was 5.50%. For the period January 1, 2005 through May 31, 2005, the discount rate used was 6.50%. In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the defined benefit pension plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%. The discount rate used for the 2004 fiscal year was 6.50%. For 2006, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Pension Cost. Similarly, for 2005 and 2004, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000. The compensation cost increase assumption used for 2006, 2005 and 2004 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the Plan.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company policy is to record those estimates in accordance with the American Institute of Certified Public Accountants Statement of Position 94-6, "Disclosure of Certain Significant Risks and Uncertainties."

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5). SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2006, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below (See Note 5.)

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 4.92%, 2.33% and 1.64% in 2006, 2005 and 2004, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company does not account separately for negative salvage, or cost of retirement obligations as defined in FASB Statement No. 143, “Accounting for Asset Retirement Obligations” and FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations.” The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At December 31, 2006 and December 31, 2005, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $14.9 million and $13.4 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company’s fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company’s consolidated financial statements.

Depreciation provisions for Unitil’s utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2006—4.40%, 2005—4.69% and 2004—4.70%.

Amortization provisions include the recovery, in 2004 and 2005, of a portion of FG&E’s former investment in Seabrook Station, a nuclear generating unit, in rates to its customers through the Seabrook Amortization Surcharge as ordered by the MDTE. FG&E’s asset related to Seabrook Station became fully-amortized in the third quarter of 2005. In addition, FG&E is amortizing the balance of its unrecovered electric generating related assets, which are recorded as Regulatory Assets, in accordance with its electric restructuring plan approved by the MDTE (See Note 5.)

Environmental Matters—The Company’s past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. In the past three years, the Company has performed work on two environmental remediation projects, the Sawyer Passway MGP Site and the Former Electric Generating Station. The Company has or will recover substantially all of the cost of the work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2006, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 5, Commitments and Contingencies. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company’s financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation currently using the fair value-based method (See Note 2.)

Sales and Consumption Taxes—The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company’s Consolidated Statements of Earnings.

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the

Company's actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) which is the authoritative pronouncement on accounting for and reporting income taxes. In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise's financial statements. FIN 48 prescribes a "more-likely-than-not" recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 applies to all tax positions related to income taxes subject to FAS 109. This includes tax positions considered to be "routine" as well as those with a high degree of uncertainty such as tax-advantaged transactions. FIN 48 effectively amends SFAS No. 5, such that all references to income taxes in SFAS No. 5 have been deleted and FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. FIN 48 creates a single model to address accounting for uncertainty in tax positions. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition, and classification and the cumulative affect of adopting FIN 48 may be recorded as an adjustment to retained earnings.

FIN 48 requires disclosures of items and amounts that would affect the Company's effective tax rate in its statement of earnings. FIN 48 also provides guidance on disclosures for interim reporting periods for accounting for income taxes, interest and penalties. The Company will adopt FIN 48 as of January 1, 2007, as required. The Company does not expect that the adoption of FIN 48 will have a significant impact on the Company's financial position and results of operations.

Dividends—The Company is currently paying a dividend at an annual rate of $1.38 per common share.

The Company's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Other Recently Issued Pronouncements—In October 2006, the FASB issued FASB Staff Position No. FAS 123(R)-5, (FSP FAS 123(R)-5), "Amendment of FASB Staff Position FAS 123(R)-1" and FASB Staff Position No. FAS 123(R)-6, (FSP FAS 123(R)-6), "Technical Corrections of FASB Statement No. 123(R)". FSP FAS 123(R)-5 addresses whether a modification of an instrument in connection with an equity restructuring should be considered a modification for purposes of applying FSP FAS 123(R)-1, "Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under revised FASB Statement No. 123(R), "Share-Based Payment", (SFAS No. 123(R)), which was issued in December 2004. FSP FAS 123(R)-6 addresses certain technical corrections of SFAS No. 123(R). SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. Prior to the adoption of SFAS No. 123(R) the Company accounted for share-based payments under SFAS No. 123, "Accounting for Stock-Based Compensation." The Company uses the fair value method for share-based payment awards and therefore the provisions of SFAS No. 123(R) have no impact on the Consolidated Financial Statements. The Company has adopted the provisions of FSP FAS 123(R)-5 and FSP FAS 123(R)-6.

In September 2006, the FASB issued FASB Statement No. 157, "Fair Value Measurements", (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect SFAS No. 157 to have an impact on the Company's Consolidated Financial Statements.

In February 2006, the FASB issued FASB Statement No. 155, "Accounting for Certain Hybrid Financial Instruments", (SFAS No. 155), which amends SFAS No.133 and FASB Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities", (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company does not expect SFAS No. 155 to have an impact on the Company's Consolidated Financial Statements.

Note 2: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

Dividend Reinvestment and Stock Purchase Plan—During 2006, the Company sold 40,365 shares of its Common Stock, at an average price of $24.78 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $1.0 million were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's Common Stock and cash payments in additional shares of the Company's Common Stock. During 2005 and 2004, the Company raised $1.0 million and $0.9 million, respectively, of additional common equity through the issuance of 38,003 and 35,310 shares, respectively, of its Common Stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired—During 2006, 2005 and 2004, Unitil did not repurchase, cancel or retire any of its common stock. The Company has adopted SFAS No. 123(R), "Accounting for Stock Based Compensation," and recognizes compensation costs at fair value at the date of grant.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. Details of the plans are as follows:

Restricted Stock Plan—On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company Common Stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided for in the Plan. Awards fully vest over a period of four years at a rate of 25% each year.

During the vesting period, dividends on restricted shares underlying the Award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the Award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit.

On February 16, 2006, 14,375 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $0.4 million. On March 8, 2005, 10,900 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $0.3 million. On April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $0.3 million. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $0.3 million. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period and was $0.4 million in 2006, including amounts for tax gross-up.

Unitil Corporation Key Employee Stock Option Plan—The "Unitil Corporation Key Employee Stock Option Plan" was a 10-year plan which began in March 1989. The number of shares underlying options granted under this plan, as well as the terms and conditions of each grant, were determined by the Key Employee Stock Option Plan Committee of the Board of Directors, subject to plan limitations. At December 31, 2006, 29,101 shares underlying options had been approved and were available for future issuance as dividend equivalents earned under the plan. All options granted under this plan vested upon grant. The 10-year period in which options could be granted under this plan expired in March 1999. The expiration date of the remaining outstanding options is November 3, 2007. The plan provides dividend equivalents on options granted, which are recorded at fair value as compensation expense. The total compensation expenses recorded by the Company with respect to this plan were $54,000, $51,000 and $49,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

Share Option Activity of the "Unitil Corporation Key Employee Stock Option Plan" is presented in the following table:

	2006	2005	2004
Beginning Options Outstanding and Exercisable	**25,000**	25,000	25,000
Dividend Equivalents Earned—Prior Years	**13,202**	11,321	9,495
Dividend Equivalents Earned—Current Year	**2,186**	1,881	1,826
Options Exercised	**—**	—	—
Ending Options Outstanding and Exercisable	**40,388**	38,202	36,321
Weighted Average Exercise Price per Share	**$11.25**	$11.89	$12.51
Range of Option Exercise Price per Share	**$12.11-$18.28**	$12.11-$18.28	$12.11-$18.28
Weighted Average Remaining Contractual Life	**0.9 years**	1.9 years	2.9 years

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's Common Stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. This plan was terminated on January 16, 2003. There was no compensation expense associated with this plan in 2006, 2005 and 2004. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of options will be made under this plan.

There were 107,000 vested and exercisable options outstanding, with an average exercise price of $27.13, at December 31, 2004, 2005 and 2006. There were no options granted or forfeited during those years.

The following summarizes certain data for the options outstanding at December 31, 2006:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$20.00-$24.99	34,500	$23.38	2.2 years
$25.00-$29.99	37,500	$25.88	4.1 years
$30.00-$34.99	35,000	$32.17	3.1 years
	107,000		

Restrictions on Retained Earnings—Unitil Corporation has no restriction on the payment of common dividends from retained earnings.

Its two retail distribution subsidiaries, UES and FG&E, do have restrictions. Under the terms of the First Mortgage Bond Indentures, UES had $14.8 million available for the payment of cash dividends on its Common Stock at December 31, 2006. Under the terms of long-term debt purchase agreements, FG&E had $7.2 million of retained earnings available for the payment of cash dividends on its Common Stock at December 31, 2006. Common dividends declared by UES and FG&E are paid exclusively to Unitil Corporation.

Preferred Stock

Unitil's two retail distribution companies, UES and FG&E, have preferred stock outstanding. At December 31, 2006, UES has a 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and FG&E has two series of Redeemable, Cumulative Preferred Stock outstanding, the 5.125% Series and the 8.00% Series.

FG&E is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, FG&E may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2006, 2005 and 2004 related to the annual redemption offer were $22,000, $11,400 and $26,900, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2006 is $117,000 per year.

On February 10, 2006, FG&E repurchased, canceled and retired 2,213 shares of its 8.00% series of Redeemable, Cumulative Preferred Stock at an aggregate par value of $221,300. FG&E used operating cash to effect this transaction.

On October 15, 2004, UES redeemed and retired the remaining three outstanding issues of its Redeemable, Cumulative Preferred Stock at par, aggregating $904,100. The three issues redeemed and retired were the 8.70% Series (aggregate par value of $215,000), the 8.75% Series (aggregate par value of $313,600) and the 8.25% Series (aggregate par value of $375,500). UES used operating cash to effect this transaction.

Note 3: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowing arrangements. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery, vehicles and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Substantially all the property of Unitil's New Hampshire utility operating subsidiary, UES, is subject to liens of indenture under which First Mortgage bonds have been issued. UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing UES Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The UES agreements further require that if UES defaults on any UES FMB securities, it would constitute a default for all UES FMB securities. The UES default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

All of the long-term debt of Unitil's Massachusetts utility operating subsidiary, FG&E, is issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of FG&E's long-term debt ranks pari passu with its other senior unsecured long-term debt. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the UES agreements, FG&E agreements require that if FG&E defaults on any FG&E long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets. In addition, the UES and FG&E long-term debt instruments and agreements contain certain restrictions on the payment of common dividends from Retained Earnings. On December 31, 2006, UES and FG&E had unrestricted Retained Earnings of $14.8 million and $7.2 million, respectively, available for the payment of common dividends. UES and FG&E pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil shareholders.

Total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $310,136, $286,368 and $3,264,421 in 2006, 2005 and 2004, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2006 is: 2007—$335,877, 2008—$363,755, 2009—$393,946, 2010—$426,643 and 2011—$462,055.

On September 26, 2006 UES issued and sold $15 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement. The proceeds from this long-term financing were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings.

FG&E, through a private placement, consummated the issuance and sale on December 21, 2005 of $15 million of unsecured long-term notes to institutional investors. The notes have a term of 25 years and a coupon rate of 5.90%. The net proceeds were used to reduce FG&E's outstanding short-term indebtedness.

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at December 31, 2006 is estimated to be in a range of up to approximately $157 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The agreements under which the long-term debt of Unitil's two principal subsidiaries, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations.

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's rate tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)

	2006	**2005**	**2004**	**2006 vs. 2005 Change**	**2005 vs. 2004 Change**
Interest Expense					
Long-term Debt	**$ 9.5**	$ 8.4	$ 8.5	$ 1.1	$(0.1)
Short-term Debt	**1.5**	1.0	0.5	0.5	0.5
Regulatory Liabilities	**0.3**	0.2	0.1	0.1	0.1
Subtotal Interest Expense	**11.3**	9.6	9.1	1.7	0.5
Interest Income					
Regulatory Assets	**(3.1)**	(2.6)	(2.3)	(0.5)	(0.3)
AFUDC and Other	**(0.4)**	(0.2)	—	(0.2)	(0.2)
Subtotal Interest Income	**(3.5)**	(2.8)	(2.3)	(0.7)	(0.5)
Total Interest Expense, net	**$ 7.8**	$ 6.8	$ 6.8	$ 1.0	$ —

Credit Arrangements

At December 31, 2006, Unitil had unsecured committed bank lines for short-term debt in the aggregate amount of $40.0 million with three banks for which it pays commitment fees. The weighted average interest rates on all short-term borrowings were 5.5%, 3.8% and 1.9% during 2006, 2005 and 2004, respectively. The Company had short-term debt outstanding through bank borrowings of approximately $26.0 million and $18.7 million at December 31, 2006 and December 31, 2005, respectively. On January 1, 2007, Unitil's unsecured committed bank lines of credit increased to $41.0 million with the same three banks.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2006, 2005 and 2004 amounted to $410,000, $301,000 and $249,000 respectively. FG&E leases its operations facility in Fitchburg, Massachusetts under an operating lease, with a primary term through January 31, 2013. The lease agreement allows for three additional five-year renewal periods at the option of FG&E. The following is a schedule of future operating lease payment obligations as of December 31, 2006:

Year Ending December 31 (000's)	
2007	$ 456
2008	456
2009	453
2010	430
2011	378
2012-2016	647
Total Future Operating Lease Payments	$2,820

The following is a schedule of future minimum lease payments and present value of net minimum lease payments under capital leases, as of December 31, 2006:

Year Ending December 31 (000's)	
2007	$233
2008	178
2009	29
2010	1
2011	1
Total Minimum Lease Payments	$442

Guarantees

The Company also provides limited guarantees on certain energy contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2006 there are $7.0 million of guarantees outstanding and these guarantees extend through October 8, 2008. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

Note 4: Energy Supply

Electricity Supply:

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from competitive retail suppliers. Retail choice has been successful for Unitil's largest customers. As of December 2006, 45% of Unitil's largest New Hampshire customers representing 18% of total New Hampshire electric sales and 87% of Unitil's largest Massachusetts customers representing 42% of total Massachusetts electric sales are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

The transition to retail choice required the divestiture of Unitil's existing power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility service. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO-NE markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

Wyman Unit No. IV—Information with respect to FG&E's ownership in Wyman Unit No. IV, at December 31, 2006, is shown below:

Joint Ownership Unit	State	Proportionate Ownership	Share of Total MW	Company's Net Book Value (000's)
Wyman Unit No. IV	ME	0.1822%	1.13	$30

FG&E continues to have a 0.1822% non-operating ownership interest in the Wyman Unit No. IV (Wyman IV), an oil-fired electric generating station located in Yarmouth, Maine. The lead operating owner of Wyman IV is FPL Energy Wyman IV, LLC. In accordance with the electric industry restructuring in Massachusetts, and pursuant to the generation assets and power supply divestiture process discussed below, FG&E effectively divested its economic interest in Wyman IV when it entered into an agreement to, among other things, sell its entire entitlement in the output from Wyman IV over the expected remaining operating life of the unit. Kilowatt-hour generation and operating expenses associated with Wyman IV are divided on the same basis as ownership. FG&E's proportionate ownership costs in Wyman IV are reflected in the Consolidated Statements of Earnings. Revenues from the entitlement sale of Wyman IV reflect a matching and collection of these costs. Accordingly, the cost associated with FG&E's ownership in Wyman IV does not have a material impact on earnings.

Power Supply Divestiture

Prior to May 1, 2003, UES purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, UES and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to UES ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, UES continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. Recovery of the contract release payments by UES from its retail customers has been approved by the NHPUC.

Unitil Power divested its long-term power supply contracts to Mirant Corporation (Mirant). The purchase of power to supply UES' Transition Service and Default Service requirements by UES from Mirant was linked to the Unitil Power divestiture. The NHPUC Order completed the state approval process for Unitil's restructuring plan under which UES implemented customer choice for its customers on May 1, 2003. The divested power supply contracts continue through October 2010. On July 14, 2003 Mirant filed for Chapter 11 Bankruptcy protection. Mirant is currently performing all of its contractual obligations to Unitil Power and has completed its power supply obligations to UES. Mirant has satisfied all of its pre-petition claims made by Unitil. On January 3, 2006 Mirant emerged from Chapter 11 Bankruptcy protection.

In March 1999, FG&E completed the sale of its 4.5% interest in the New Haven Harbor Station generating unit. FG&E divested its remaining owned generation assets and long-term power supply contracts to Select Energy, Inc., a subsidiary of Northeast Utilities. Under the Select Energy contract, which was approved by the MDTE in January 2000, and went into effect February 1, 2000, FG&E began selling the entire output from its remaining long-term power supply contracts and the output of its two joint ownership units, Millstone Unit 3 and Wyman Unit No. IV, to Select Energy. Upon the sale of FG&E's share of Millstone Unit 3 in 2001, this portion of the contract sale ceased. Effective with the termination of the Purchased Power Contract between FG&E and Linweave, Inc. on December 1, 2004, this portion of the contract sale also ceased. On December 30, 2005 Select Energy assigned the FG&E contracts portfolio to Constellation Energy Commodities Group effective January 1, 2006. Recovery of all costs associated with the divestiture of the FG&E power supply portfolio has been approved by the MDTE.

In connection with the implementation of retail choice, Unitil Power and FG&E divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next four to six years, is $126.1 million as of December 31, 2006 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet (see Regulatory Assets table in Note 1.) Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into wholesale electric power supply contracts with various wholesale suppliers.

FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service. MDTE policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, with each 12 month contract providing 50% of the class requirements. The MDTE is investigating alternatives to the current procurement policy for all accounts, other than the large general accounts. This process could potentially lead to the procurement of FG&E Default Service power supply for longer durations in order to provide more price stability for smaller customers throughout Massachusetts for whom competitive retail options are relatively scarce.

UES currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. UES procures Default Service for its largest general service accounts through successive competitive solicitations of three-months duration and procures Default Service for all other customers through a series of two one-year contracts and two three-year contracts with each contract covering 25% of the total requirements of the group. The first two contracts were of 6-months and 18-months duration in order to stagger the start dates of future 1-year and 3-year procurements.

Regional Transmission and Power Markets

FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the Regional Transmission Organization (RTO) in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDTE and NHPUC.

Gas Supply:

FG&E's natural gas customers now have the opportunity to purchase their natural gas supply from third-party vendors, though most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E purchases natural gas from domestic and Canadian suppliers under contracts of one year or less, as well as from producers and marketers on the spot market and arranges for the transportation to its distribution facilities under long-term contracts with the Tennessee interstate pipeline. FG&E has a four-year contract for liquefied natural gas (LNG) supply ending in 2008, which was approved by the MDTE. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2004 through 2006.

Sources of Gas Supply

(Expressed as percent of total MMBtu of gas purchased)

	2006	2005	2004
Natural Gas:			
Domestic firm	**84.2%**	84.8%	85.0%
Canadian firm	**2.0%**	3.4%	5.4%
Domestic spot market	**11.0%**	9.3%	5.9%
Total natural gas	**97.2%**	97.5%	96.3%
Supplemental gas	**2.8%**	2.5%	3.7%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2006	2005	2004
Cost of gas purchased and sold per MMBtu	**$11.18**	$10.83	$ 8.42
Percent Increase (Decrease) from prior year	**3.2%**	28.7%	17.9%

FG&E has available under firm contract 14,057 MMBtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Note 5: Commitments and Contingencies

Regulatory Matters

Overview—Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on an historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, all of Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the providers of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next four to six years, is $126.1 million as of December 31, 2006 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet (See Regulatory Assets table in Note 1.) Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E—Electric Division—FG&E provides electric distribution service to customers under unbundled distribution rates approved by the MDTE. Its current retail electric distribution rates were approved by the MDTE in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of December 31, 2006, approximately 53 percent of FG&E's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large C&I customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $33.3 million at December 31, 2006, and $34.4 million at December 31, 2005, and is expected to be recovered in FG&E's rates over the next four to six years. In addition, as of December 31, 2006, FG&E had recorded on its balance sheet $50.0 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates (See Note 1.)

On March 7, 2006, the MDTE approved FG&E's 2003 and 2004 annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. FG&E's 2005 and 2006 filings, which are subject to investigation, are pending. The Company expects that these filings will be approved without material changes or adjustments.

FG&E—Gas Division—FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDTE in 2002. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On January 26, 2007, the MDTE approved a rate Settlement Agreement (Settlement) which FG&E and the Attorney General of Massachusetts had signed and filed with the MDTE for FG&E's Gas Division on November 29, 2006. Under the Settlement, FG&E will phase-in gas distribution rate changes with an initial rate increase of $1.2 million as of February 1, 2007, and an additional $1.0 million increase on November 1, 2007. The Settlement also includes agreement on several other rate matters and service quality performance measures for the company's gas division in the areas of safety, customer service and satisfaction.

On September 7, 2006, the MDTE issued an order allowing FG&E to recover its actual gas and electric supply-related bad debt effective December 1, 2005. Prior to this final approval, FG&E had recovered supply-related bad debt based on a fixed rate formula that was resulting in a significant underrecovery of these costs. On September 27, 2006, the Attorney General filed a Petition for Appeal with the Massachusetts Supreme Judicial Court seeking to set aside the MDTE's order of September 7, 2006. FG&E intends to support the MDTE's order but the Company cannot predict the outcome of the Attorney General's appeal at this time.

UES—UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were approved by the NHPUC in 2006 under the Settlement Agreement discussed below. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of December 31, 2006, approximately 80 percent of UES' electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large C&I customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery, including certain charges that are subject to annual or periodic reconciliation or future review. As of December 31, 2006, UES had recorded on its balance sheets $42.6 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately four years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 17, 2006, UES made its third annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2006, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. The NHPUC approved the filing on April 28, 2006.

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement (Agreement) resolving all issues in its electric distribution base rate case filed in November, 2005. The terms of the Agreement provide for an increase in base distribution rates of $2.3 million annually, effective as of January 1, 2006. Additionally, the Agreement authorizes two step increases in base distribution rates, related to utility plant additions in 2006, of approximately $0.4 million and $0.1 million annually, effective as of November 1, 2006 and May 1, 2007, respectively. Also, the Agreement provides for the recovery of approximately $0.3 million annually of supply-related operating and administrative costs through default energy service rates and a reduction of approximately $0.6 million in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives. The stipulated rate of return under the settlement is 8.70%, including a return on equity of 9.67%. The Agreement also authorizes a temporary rate surcharge for recovery of certain rate case expenses and recoupment of the authorized distribution rate increase from January through October 2006.

FERC—Wholesale Power Markets—FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the RTO in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England are performed on a regional basis. The Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDTE and NHPUC.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2006, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—FG&E continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary closure of the site. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E has recovered the environmental response costs incurred at this former MGP site in gas rates pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition FG&E has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

FG&E is in the process of developing long range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2006 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of the site. A corresponding regulatory asset was recorded to reflect the future rate recovery for these costs. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

The Company's ultimate liability for future environmental remediation costs may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

Note 6: Bad Debts

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2004 – 2006.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	Additions: (A) Provision	Additions: Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2006					
Electric	**$342,791**	**$1,963,222**	**$136,399**	**$1,178,310**	**$1,264,102**
Gas	**110,031**	**1,325,650**	**134,802**	**1,132,324**	**438,159**
Other	**16,926**	**29,313**	**1,780**	**13,493**	**34,526**
	$469,748	**$3,318,185**	**$272,981**	**$2,324,127**	**$1,736,787**
Year Ended December 31, 2005					
Electric	$392,824	$ 714,917	$116,290	$ 881,240	$ 342,791
Gas	89,602	721,171	116,366	817,108	110,031
Other	18,297	9,602	—	10,973	16,926
	$500,723	$1,445,690	$232,656	$1,709,321	$ 469,748
Year Ended December 31, 2004					
Electric	$395,432	$ 821,077	$121,974	$ 945,659	$ 392,824
Gas	132,964	524,905	96,411	664,678	89,602
Other	13,080	10,500	—	5,283	18,297
	$541,476	$1,356,482	$218,385	$1,615,620	$ 500,723

(A) In 2006, the Company recorded a provision for the energy commodity portion of bad debts of $1.7 million. This provision was recognized in Purchased Electricity and Purchased Gas expense as the associated electric and gas utility revenues were billed. Purchased Electricity and Purchased Gas costs are recovered from customers through periodic rate reconciling mechanisms. Prior to 2006, the commodity portion of bad debt expense was recognized in Purchased Electricity and Purchased Gas expense when the accounts were actually written off from accounts receivable.

Note 7: Income Taxes

In June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise's financial statements. FIN 48 prescribes a "more-likely-than-not" recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 applies to all tax positions related to income taxes subject to FAS 109. This includes tax positions considered to be routine as well as those with a high degree of uncertainty such as tax-advantaged transactions. FIN 48 effectively amends SFAS No. 5, such that all references to income taxes in SFAS No. 5 have been deleted and FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. FIN 48 creates a single model to address accounting for uncertainty in tax positions. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition, and classification and the cumulative affect of adopting FIN 48 may be recorded as an adjustment to retained earnings.

FIN 48 requires disclosures of items and amounts that would affect the Company's effective tax rate in its statement of earnings. FIN 48 also provides guidance on disclosures for interim reporting periods for accounting for income taxes, interest and penalties. The Company will adopt FIN 48 as of January 1, 2007, as required. The Company does not expect that the adoption of FIN 48 will have a significant impact on the Company's financial position and results of operations.

Federal Income Taxes were provided for the following items for the years ended December 31, 2006, 2005 and 2004, respectively:

	2006	2005	2004
Current Federal Tax Provision (000's):			
Operating Income	**$3,448**	$3,671	$ 438
Total Current Federal Tax Provision	**3,448**	3,671	438
Deferred Federal Tax Provision (000's)			
Property Plant and Equipment	**(656)**	(841)	2,669
Abandoned Properties	**—**	(796)	(769)
Accrued Revenue	**795**	1,296	1,779
Deferred Compensation and Pensions	**271**	299	(3)
Regulatory Assets and Liabilities	**(5)**	—	(194)
Net Operating Loss Carryforward	**—**	—	92
Alternative Minimum Tax	**—**	—	(355)
Other, net	**(87)**	(180)	(151)
Total Deferred Federal Tax Provision (Benefit)	**318**	(222)	3,068
Total Federal Tax Provision	**$3,766**	$3,449	$3,506

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2006, 2005 and 2004 are shown in the table below. In addition to the provisions for state income taxes, the Company recorded provisions of $211,000, $179,000 and $179,000 in 2006, 2005 and 2004, respectively for state Business Enterprise taxes which are included in Local Property and Other Taxes on the consolidated statements of earnings.

Federal and State Tax Provisions (000's)	2006	2005	2004
Federal			
Current	**$3,448**	$3,671	$ 438
Deferred	**318**	(222)	3,068
Total Federal Tax Provision	**3,766**	3,449	3,506
State			
Current	**337**	844	602
Deferred	**163**	(18)	98
Total State Tax Provision	**500**	826	700
Total Provision for Federal and State Income Taxes	**$4,266**	$4,275	$4,206

The differences between the Company's provisions for Income Taxes, including the provision for Business Enterprise taxes, and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2006	2005	2004
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**5**	5	5
Abandoned Property	**—**	(6)	(6)
Utility Plant Differences	**(4)**	—	1
Other, Net	**1**	—	—
Effective Income Tax Rate	**36%**	33%	34%

Temporary differences which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	2006	2005
Property, Plant and Equipment	**$ 27,209**	$27,186
Accrued Revenue	**14,687**	13,204
Regulatory Assets and Liabilities	**8,905**	8,700
Retirement Benefit Obligations	**(17,644)**	1,615
Other	**1,369**	1,592
Total Deferred Income Tax Liabilities	**$ 34,526**	$52,297

Note 8: Retirement Benefit Plans

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit pension plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

In September 2006, the FASB issued SFAS No. 158 which requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding

Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates. See below for a table showing the incremental effect of applying SFAS No. 158 on individual line items of the Company's Consolidated Balance Sheet at December 31, 2006.

Incremental Effect of Applying SFAS No. 158—The table below shows the incremental effect of applying SFAS No. 158 on individual line items of the Company's Consolidated Balance Sheet at December 31, 2006.

Incremental Effect of Applying SFAS No. 158
On Individual Line Items of the Company's Consolidated Balance Sheet
December 31, 2006
(000's)

	Before Application of SFAS No. 158	SFAS No. 158 Adjustments	After Application of SFAS No. 158
Prepaid Pension	$ 11,000	$(11,000)	$ —
Regulatory Assets	5,261	26,455	31,716
Total Assets	467,972	15,455	483,427
Other Current Liabilities	$ —	$ 70	$ 70
Retirement Benefit Obligations	13,969	35,694	49,663
Deferred Income Taxes	2,665	(20,309)	(17,644)
Total Capitalization and Liabilities	467,972	15,455	483,427

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period. The Company expects to contribute approximately $4.0 million to fund its pension plan in 2007.

Defined Benefit Pension Plan—The Company sponsors the Unitil Corporation Retirement Plan (the Plan), a defined benefit pension plan covering substantially all of its employees. Under the Plan, retirement benefits are based upon an employee's level of compensation and length of service.

On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF)) to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis. As a result of this order, FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106 and amortizes increases and/or decreases in that deferral balance into the PAF for recovery over a three year period.

On October 6, 2006, the NHPUC approved a Settlement Agreement, resolving all issues in UES' electric distribution base rate case filed in November 2005. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates. Under the Settlement Agreement UES will amortize its deferred pension costs as these amortization costs are recovered over a six year period in base rates.

The following tables show the components of net periodic pension cost (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

Components of NPPC (000's)	**2006**	**2005**	**2004**
Service Cost	**$ 1,800**	$ 1,458	$ 1,302
Interest Cost	**3,153**	3,085	3,028
Expected Return on Plan Assets	**(3,775)**	(3,404)	(3,393)
Amortization of Prior Service Cost	**107**	107	101
Amortization of Net Loss	**1,324**	1,146	944
Subtotal NPPC	**2,609**	2,392	1,982
Amounts Capitalized and Deferred	**(1,014)**	(1,751)	(1,926)
NPPC Recognized	**$ 1,595**	$ 641	$ 56

The estimated amortization related to Actuarial Loss and Prior Service Cost included in NPPC over the next fiscal year is $1.4 million.

Key Assumptions (Weighted Average)	**2006**	**2005**	**2004**
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.50%**	5.50%	6.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Used to Determine NPPC for years ended December 31:			
Discount Rate	**5.50%**	6.00%	6.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%	8.75%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%

The following table represents information on the Plan's Projected Benefit Obligation (PBO), fair value of plan assets and the Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	**2006**	**2005**
PBO at Beginning of Year	**$ 58,586**	$ 49,757
Service Cost	**1,800**	1,458
Interest Cost	**3,153**	3,085
Plan Amendments	**—**	110
Benefits Paid	**(2,476)**	(2,404)
Actuarial Loss	**964**	6,580
PBO at End of Year	**$ 62,027**	$ 58,586
Change in Plan Assets (000's):		
Fair Value of Plan Assets at Beginning of Year	**$ 44,535**	$ 42,304
Actual Return on Plan Assets	**4,958**	2,135
Employer Contributions	**2,510**	2,500
Benefits Paid	**(2,476)**	(2,404)
Fair Value of Plan Assets at End of Year	**$ 49,527**	$ 44,535
PBO and Funded Status (000's):		
Fair Value of Plan Assets	**$ 49,527**	$ 44,535
PBO	**62,027**	58,586
Funded Status	**(12,500)**	(14,051)
Unrecognized Actuarial Loss and Prior Service Cost	**—**	25,150
Prepaid (Unfunded) Pension Obligation	**$(12,500)**	$ 11,099

The following table represents the Plan's weighted-average investment asset allocations at December 31:

	Target Allocation 2007	Actual Allocation at December 31		
		2006	2005	2004
Equity Securities	58-62%	**61%**	60%	61%
Debt Securities	38-42%	**39%**	40%	39%
Real Estate and Other	0-2%	**0%**	0%	0%
Total		**100%**	**100%**	**100%**

The desired investment objective is a long-term rate of return on assets that is approximately 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plan has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The following tables represent Plan contributions and benefit payments. There were no participant contributions.

(000's)	2006	2005	2004
Employer Contributions	**$2,510**	$2,500	$2,000
Benefit Payments	**$2,476**	$2,404	$2,280

Estimated Future Benefit Payments					
2007	2008	2009	2010	2011	2012-2016
$2,730	$2,873	$2,918	$3,115	$3,207	$18,422

Postretirement Benefits—The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) primarily to provide health care and life insurance benefits to employees and retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS No. 106-1) and Statement No. 106-2 (SFAS No. 106-2), "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary's annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS No. 106-1 and SFAS No. 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation and how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods. On January 28, 2005, the final Medicare Part D Prescription Drug Rules were posted to the Federal Register. Based on these rules, the Company's estimated PBOP Projected Benefit Obligation was reduced by $5.1 million. Also, the Company has estimated that its annual PBOP costs will be reduced by $0.4 million under the Act. These reductions are reflected in the Company's Consolidated Financial Statements. The Company's health care insurance provider has concluded that the Company's PBOP Plan is equal to or better than standard Medicare Part D coverage. Additionally, the Company's recognition of the Act is not expected to have any impact on the rate of participation in the PBOP Plan or per capita claims.

As discussed above, on October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis. As discussed above, on October 6, 2006, the NHPUC approved a Settlement Agreement, resolving all issues in UES' electric distribution base rate case filed in November 2005. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates.

The components of net periodic postretirement benefit cost (NPPBC) are as follows:

Components of NPPBC (000's)	2006	2005	2004
Service Cost	**$ 1,283**	$ 993	$ 899
Interest Cost	**2,028**	1,795	1,827
Expected Return on Plan Assets	**(194)**	(41)	—
Amortization of Prior Service Cost	**1,360**	1,401	1,458
Amortization of Transition Obligation	**21**	21	21
Amortization of Net Loss	**160**	—	—
Subtotal NPPC	**4,658**	4,169	4,205
Amounts Capitalized and Deferred	**(2,217)**	(2,051)	(2,498)
NPPBC Recognized	**$ 2,441**	$ 2,118	$ 1,707

The estimated amortization related to Actuarial Loss and Prior Service Cost included in NPPBC over the next fiscal year is $1.5 million.

The following table includes assumptions used in determining the various PBOP values.

Key Assumptions (Weighted Average)	2006	2005	2004
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.50%**	5.50%	6.50%
Rate of Compensation Increase	**N/A**	N/A	N/A
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	9.00%	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2016	2013
Used to Determine NPPBC for years ended December 31:			
Discount Rate	**5.50%**	6.00%	6.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%/5.50%**[1]	8.50%/5.50%[1]	N/A
Rate of Compensation Increase	**N/A**	N/A	N/A
Health Care Cost Trend Rate Assumed for Next Year	**9.00%**	8.00%	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013	2013

(1) Funding of the PBOP Plan is made into two VEBT's; one is a union VEBT and the other is a non-union VEBT. The expected long-term rate of return on plan assets for the union VEBT is 8.50%. The non-union VEBT is subject to income taxes and therefore the expected long-term rate of return on plan assets is 5.50%, reflecting the effect of taxes.

Assumed health care cost trend rates have a significant effect on the amounts reported. A one-percentage-point change in the assumed health care cost trend rates would have the following effects:

1-Percentage Point Increase (000's)	2006	2005	2004
Effect on Total of Service and Interest Cost	**$ 683**	$ 526	$ 564
Effect on Postretirement Benefit Obligation	**$ 6,381**	$ 5,917	$ 4,079
1-Percentage Point Decrease (000's)			
Effect on Total of Service and Interest Cost	**$ (530)**	$ (413)	$ (438)
Effect on Postretirement Benefit Obligation	**$(5,091)**	$(4,737)	$(3,290)

The following table represents information on the PBOP Plan's fair value of plan assets and the PBOP Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2006	2005
PBO at Beginning of Year	**$ 37,528**	$ 27,917
Service Cost	**1,283**	993
Interest Cost	**2,028**	1,795
Plan Amendments	**—**	(1,797)
Benefits Paid	**(1,540)**	(1,334)
Actuarial (Gain) or Loss	**(1,192)**	9,954
PBO at End of Year	**$ 38,107**	$ 37,528

Change in Plan Assets (000's):	2006	2005
Fair Value of Plan Assets at Beginning of Year	**$ 2,304**	$ 1,101
Actual Return on Plan Assets	**78**	37
Employer Contributions	**2,210**	2,500
Benefits Paid	**(1,540)**	(1,334)
Fair Value of Plan Assets at End of Year	**$ 3,052**	$ 2,304

Obligation and Funded Status (000's):	2006	2005
Fair Value of Plan Assets	**$ 3,052**	$ 2,304
PBO	**38,107**	37,528
Funded Status	**(35,055)**	(35,224)
Unrecognized Actuarial Loss and Prior Service Cost	**—**	30,339
(Unfunded) PBOP Obligation	**$(35,055)**	$ (4,885)

The following tables represent PBOP contributions and benefit payments made in 2004 – 2006 and estimated future benefit payments. There were no participant contributions.

(000's)	Expected 2007	2006	2005	2004
Employer Contributions	**$2,500**	**$2,210**	$2,500	$2,355
Benefit Payments	**$1,398**	**$1,540**	$1,334	$1,257

Estimated Future Benefit Payments

2008	2009	2010	2011	2012-2016
$1,496	$1,585	$1,758	$1,898	$11,019

Supplemental Executive Retirement Plan—The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors. The cost associated with the SERP amounted to approximately $305,000, $190,000 and $194,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

The components of net periodic SERP cost are as follows:

Components of Net Periodic SERP Cost (000's)	2006	2005	2004
Service Cost	**$148**	$ 90	$ 89
Interest Cost	**103**	80	75
Amortization of Prior Service Cost	**(2)**	(2)	3
Amortization of Transition Obligation	**17**	17	17
Amortization of Net Loss	**39**	5	10
Net Periodic SERP Cost	**$305**	$190	$194

The estimated amortization related to Actuarial Loss and Prior Service Cost included in Net Periodic SERP Cost over the next fiscal year is less than $0.1 million.

The following table includes information regarding Unitil's SERP costs as well as key actuarial assumptions:

Additional Information (000's):	2006	2005	2004
Accumulated Benefit Obligation	**$ 670**	$ 800	$ 673
Weighted-Average Assumptions			
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.50%**	5.50%	6.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Used to Determine Net Periodic SERP Cost for years ended December 31:			
Discount Rate	**5.50%**	6.50%	6.50%
Expected Long-Term Rate of Return on Plan Assets	**N/A**	N/A	N/A
Rate of Compensation Increase	**3.50%**	3.50%	3.50%

The following table represents information on the SERP's Projected Benefit Obligation (PBO), fair value of plan assets and the plan's funded status.

Change in PBO (000's)	2006	2005
PBO at Beginning of Year	**$1,910**	$1,218
Service Cost	**148**	90
Interest Cost	**103**	80
Benefits Paid	**(72)**	(72)
Actuarial (Gain) or Loss	**90**	594
PBO at End of Year	**$2,179**	$1,910
Change in Plan Assets (000's):		
Fair Value of Plan Assets at Beginning of Year	**$ —**	$ —
Actual Return on Plan Assets	**—**	—
Employer Contributions	**72**	72
Benefits Paid	**(72)**	(72)
Fair Value of Plan Assets at End of Year	**$ —**	$ —

Obligation and Funded Status (000's):	**2006**	**2005**
Fair Value of Plan Assets	**$ —**	$ —
PBO	**2,179**	1,910
Funded Status	**(2,179)**	(1,910)
Unrecognized Prior Service Cost and Actuarial Loss	**—**	767
(Unfunded) SERP Liability	**$(2,179)**	$(1,143)

The following tables represent SERP contributions and benefit payments made in 2004 – 2006 and estimated future benefit payments. There were no participant contributions.

(000's)	**2006**	**2005**	**2004**
Employer Contributions	**$72**	$72	$72
Benefit Payments	**$72**	$72	$72

Estimated Future Benefit Payments					
2007	**2008**	**2009**	**2010**	**2011**	**2012-2016**
$71	$69	$66	$63	$61	$1,256

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k)) under Section 401(k) of the Internal Revenue Code, covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. The Company matches contributions, with a maximum matching contribution of 3% of current compensation. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company Common Stock fund. Participants are 100% vested in contributions made on their behalf, once they have completed three years of service. The Company's share of contributions to the plan was $528,000, $503,000 and $499,000 for the years ended December 31, 2006, 2005, and 2004, respectively.

Note 9: Earnings Per Share

The following table reconciles basic and diluted earnings per share, assuming all dilutive outstanding stock options were converted to common shares per SFAS No. 128, "Earnings per Share."

(000's except share and per share data)	**2006**	**2005**	**2004**
Earnings Available to Common Shareholders	**$ 7,900**	$ 8,397	$ 8,011
Weighted Average Common Shares Outstanding—Basic	**5,597,465**	5,551,420	5,509,321
Plus: Diluted Effect of Incremental Shares	**14,269**	16,298	15,514
Weighted Average Common Shares Outstanding—Diluted	**5,611,734**	5,567,718	5,524,835
Earnings per Share—Diluted	**$ 1.41**	$ 1.51	$ 1.45

Weighted average options to purchase 72,500, 72,500 and 35,000 shares of Common Stock were outstanding during 2006, 2005 and 2004, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive.

Note 10: Segment Information

Unitil reported four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil is engaged principally in the retail sale and distribution of electricity in New Hampshire and both electricity and natural gas service in Massachusetts through its retail distribution subsidiaries UES and FG&E. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty, Unitil Service and the holding company are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries' use. Unitil Resources and Usource are included in the Non-Regulated column below.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on cost allocation factors included in rate applications approved by the NHPUC and MDTE. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2006, 2005 and 2004.

Year Ended December 31, 2006 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$225,154**	**$ 33,271**	**$ —**	**$2,436**	**$260,861**
Interest Income	**2,926**	**129**	**405**	**—**	**3,460**
Interest Expense	**9,508**	**1,137**	**580**	**76**	**11,301**
Depreciation & Amortization Expense	**11,213**	**3,489**	**1,301**	**66**	**16,069**
Income Tax Expense (Benefit)	**4,096**	**142**	**147**	**(119)**	**4,266**
Segment Profit (Loss)	**6,984**	**481**	**634**	**(199)**	**7,900**
Segment Assets	**346,744**	**113,065**	**22,685**	**933**	**483,427**
Capital Expenditures	**26,286**	**7,186**	**154**	**16**	**33,642**
Year Ended December 31, 2005 (000's)					
Revenues	$197,339	$ 32,767	$ —	$2,039	$232,145
Interest Income	2,516	47	217	—	2,780
Interest Expense	8,144	858	569	50	9,621
Depreciation & Amortization Expense	14,514	3,098	1,443	68	19,123
Income Tax Expense (Benefit)	3,888	426	(41)	2	4,275
Segment Profit (Loss)	6,957	911	536	(7)	8,397
Segment Assets	328,208	98,184	22,516	1,173	450,081
Capital Expenditures	17,211	6,936	220	—	24,367
Year Ended December 31, 2004 (000's)					
Revenues	$183,889	$ 28,685	$ —	$1,563	$214,137
Interest Income	2,051	130	166	—	2,347
Interest Expense	7,601	906	595	19	9,121
Depreciation & Amortization Expense	14,431	2,709	1,622	68	18,830
Income Tax Expense (Benefit)	3,729	507	58	(88)	4,206
Segment Profit (Loss)	6,649	1,202	300	(140)	8,011
Segment Assets	340,800	94,239	21,069	902	457,010
Capital Expenditures	17,566	5,111	245	—	22,922

Note 11: Quarterly Financial Information (unaudited; 000's except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2006	2005	2006	2005	2006	2005	2006	2005
Total Operating Revenues	**$70,703**	$60,000	**$60,226**	$51,439	**$66,287**	$56,654	**$63,645**	$64,052
Operating Income	**$ 3,935**	$ 4,504	**$ 3,329**	$ 3,311	**$ 3,812**	$ 3,240	**$ 4,779**	$ 4,486
Net Income Applicable to Common	**$ 2,013**	$ 2,671	**$ 1,401**	$ 1,497	**$ 1,792**	$ 1,562	**$ 2,694**	$ 2,667
	Per Share Data:							
Earnings Per Common Share	**$ 0.36**	$ 0.48	**$ 0.25**	$ 0.27	**$ 0.32**	$ 0.28	**$ 0.48**	$ 0.48
Dividends Paid Per Common Share	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345

On November 4, 2005, UES filed a request for an electric base rate increase with the NHPUC. On February 3, 2006, the NHPUC issued an order setting temporary rates based on which any final rate change approved by the NHPUC would be reconciled to be effective as of January 1, 2006. On August 24, 2006 a settlement agreement resolving the base rate case among UES, the Office of the Consumer Advocate, and the NHPUC Staff was filed, and on October 6, 2006, the agreement was approved by the NHPUC.

In the second quarter of 2006, when the rate filing was under review, the Company recorded an estimate of expected revenue and expenses for the first six months of 2006 based on the temporary rate order effective date and the current status of proceedings. In the third quarter of 2006, based on the approval by the NHPUC of the settlement agreement, the Company recorded final revenue and expense figures, aligning previously estimated amounts with the settlement agreement.

In the Company's judgment, the impact of the estimated and final revenues and expenses recorded in 2006 related to this rate proceeding did not have a material impact on the interim quarterly results as reported on Form 10-Q and the Company's current year operating income.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). In addition, management is required to report their assessment, including their evaluation criteria, on the design and operating effectiveness of the Company's internal control over financial reporting in Form 10-K.

The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The Company's internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles. The Company's internal control over financial reporting includes policies and procedures which provide reasonable assurances that transactions are properly initiated, authorized, recorded, reported and disclosed, and provide reasonable assurances regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

During 2006, management conducted an assessment of the Company's internal control over financial reporting reflected in the financial statements, based upon criteria established in the "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on management's assessment, which included a comprehensive review of the design and operating effectiveness of the Company's internal control over financial reporting, management believes the Company's internal control over financial reporting is designed and operating effectively as of December 31, 2006.

Vitale, Caturano and Company, an independent registered public accounting firm, has audited management's assessment of the effectiveness of the internal control over financial reporting as stated in their report which is included herein.

Item 9B. Other Information

None

PART III

Item 10. Directors and Executive Officers of the Registrant

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the 2006 Proxy Statement as filed with the Securities and Exchange Commission.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Compensation Discussion and Analysis" and "Compensation of Named Executive Officers" sections of the 2006 Proxy Statement as filed with the Securities and Exchange Commission.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the "Beneficial Ownership" and "As to the Election of Directors" sections of the 2006 Proxy Statement as filed with the Securities and Exchange Commission, as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions

None

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the 2006 Proxy Statement as filed with the Securities and Exchange Commission.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2006 and 2005
- Consolidated Statements of Earnings for the years ended December 31, 2006, 2005, and 2004
- Consolidated Statements of Capitalization—December 31, 2006 and 2005
- Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005, and 2004
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2006, 2005, and 2004
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) **– LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992 and April 30, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.4	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.5	Articles of Exchange of CECo, E&H, and the Company—Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.6	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (FG&E) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.7	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, FG&E and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989

Exhibit Number	Description of Exhibit	Reference*
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002
4.2	FG&E Purchase Agreement dated March 20, 1992 for the 8.55% Senior Notes due March 31, 2004.	Exhibit 4.18 to Form 10-K for 1993
4.3	FG&E Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.4	FG&E Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.5	FG&E Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.6	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.7	FG&E Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.8	FG&E Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
4.9	Thirteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of September 26, 2006.	**
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2003
10.5	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 10-Q for September 30, 2003
10.6	Key Employee Stock Option Plan effective January 17, 1989.	Exhibit 10.56 to Form 8 dated April 12, 1989
10.7	Unitil Corporation Key Employee Stock Option Plan Award Agreement.	Exhibit 10.63 to Form 10-K for 1989
10.8	Unitil Corporation Management Performance Compensation Plan.	Exhibit 10.94 to Form 10-K/A for 1993
10.9	Unitil Corporation Supplemental Executive Retirement Plan effective as of January 1, 1987.	Exhibit 10.95 to Form 10-K/A for 1993
10.10	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998

Exhibit Number	Description of Exhibit	Reference*
10.11	Unitil Corporation Management Incentive Plan.	Exhibit 10.13 to Form 10-K for 1998
10.12	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.13	Purchase and Sale Agreement For New Haven Harbor.	Exhibit 10.15 to Form 10-K for 1999
10.14	Labor Agreement effective June 1, 2000 between CECo and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.13 to Form 10-K for 2000
10.15	Labor Agreement effective June 1, 2000 between E&H and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.14 to Form 10-K for 2000
10.16	Labor Agreement effective June 1, 2000 between FG&E and The Utility Workers of America, AFL-CIO., Local Union No. B340, The Brotherhood of Utility Workers Council.	Exhibit 10.15 to Form 10-K for 2000
10.17	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.18	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.19	Unitil Corporation Tax Deferred Savings and Investment Plan—Trust Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2004
10.20	Employment Agreement effective as of November 1, 2006 by and between Unitil Corporation and Robert G. Schoenberger.	Exhibit 10.1 to Form 8-K dated September 29, 2006
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
23.2	Consent of Independent Registered Public Accounting Firm.	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith

Exhibit Number	Description of Exhibit	Reference*
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** In accordance with Item 601(b)(4)(iii)(A) of Federal Securities Regulation S-K, the instrument defining the debt of the Registrant and its subsidiary, described above, has been omitted but will be furnished to the Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 21, 2007

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board of Directors, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 21, 2007
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 21, 2007
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	February 21, 2007
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 21, 2007
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 21, 2007
/s/ ROSS B. GEORGE **Ross B. George**	Director	February 21, 2007
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 21, 2007
/s/ CHARLES H. TENNEY, III **Charles H. Tenney, III**	Director	February 21, 2007
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 21, 2007
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 21, 2007
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 21, 2007
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 21, 2007
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 21, 2007
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	February 21, 2007

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2006	2005	2004
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$8,033**	$8,553	$8,226
Less: Dividend Requirements on Preferred Stock	**133**	156	215
Net Income Applicable to Common Stock	**$7,900**	$8,397	$8,011
Average Number of Common Shares Outstanding—Basic	**5,597**	5,551	5,509
Dilutive Effect of Stock Options and Restricted Stock	**15**	17	16
Average Number of Common Shares Outstanding—Diluted	**5,612**	5,568	5,525
Earnings Per Share—Basic	**$ 1.41**	$ 1.51	$ 1.45
Earnings Per Share—Diluted	**$ 1.41**	$ 1.51	$ 1.45

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
(000's, except ratios)	**2006**	2005	2004	2003	2002
Earnings:					
Net Income, per Consolidated Statement of Earnings	**$ 8,033**	$ 8,553	$ 8,226	$ 7,958	$ 6,088
Federal and State Income Taxes included in Operations	**4,266**	4,275	4,206	3,551	2,490
Interest on Long-Term Debt	**9,404**	8,319	8,394	8,088	8,254
Amortization of Debt Discount Expense	**112**	104	98	82	81
Other Interest	**1,675**	1,046	629	1,070	1,038
Total	**$23,490**	$22,297	$21,553	$20,749	$17,951
Fixed Charges:					
Interest of Long-Term Debt	**$ 9,404**	$ 8,319	$ 8,394	$ 8,088	$ 8,254
Amortization of Debt Discount Expense	**112**	104	98	82	81
Other Interest	**1,675**	1,046	629	1,070	1,038
Pre-tax Preferred Stock Dividend Requirements	**208**	234	325	391	419
Total	**$11,399**	$ 9,703	$ 9,446	$ 9,631	$ 9,792
Ratio of Earnings to Fixed Charges	**2.06**	2.30	2.28	2.15	1.83

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has six wholly-owned subsidiaries, five of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The sixth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our report dated February 2, 2007, accompanying the December 31, 2006 and December 31, 2005 consolidated financial statements included in the Annual Report of Unitil Corporation and subsidiaries on Form 10-K for the year ended December 31, 2006 in the Registration Statements of Unitil Corporation and subsidiaries on Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000).

/s/ Vitale, Caturano & Company Ltd.

Boston, Massachusetts
February 20, 2007

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 17, 2005, accompanying the December 31, 2004 consolidated financial statements included in the Annual Report of Unitil Corporation and subsidiaries on Form 10-K for the year ended December 31, 2004. We hereby consent to the incorporation by reference of said report in the Registration Statements of Unitil Corporation and subsidiaries on Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000.)

/s/ GRANT THORNTON, LLP

Boston, Massachusetts
February 20, 2007

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2007

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2007

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2007

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 21, 2007
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 21 , 2007
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 21, 2007

Shareholder Information

2007 Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at the office of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 19, 2007, at 10:30 a.m.

Investor Information

The Company's Transfer Agent, Computershare Trust Company, N.A. ("Computershare"), is responsible for all shareholder records, including the distribution of dividends, tax documents and proxy materials. Shareholder requests regarding these and other matters can be addressed by corresponding directly with Computershare at:

Mail: PO Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com/equiserve

For information about the Company and your investment, you may also call the Company directly, toll-free, at: 800-999-6501 and ask for the Shareholder Representative; or visit the Investor Relations page at www.unitil.com.

Shareholder Programs

Dividend Reinvestment Plan

A Dividend Reinvestment and Stock Purchase Plan is available to all holders of record of the Company's Common Stock. This Plan provides shareholders with an economical means to increase their investment in the Company each quarter by reinvesting their dividends without broker fees. For additional information or enrollment, please contact the Company or Computershare.

Dividend Direct Deposit

Dividend Direct Deposit Service is available without charge to shareholders of record of the Company's Common Stock. For further information or enrollment in this service, please contact the Company or Computershare.

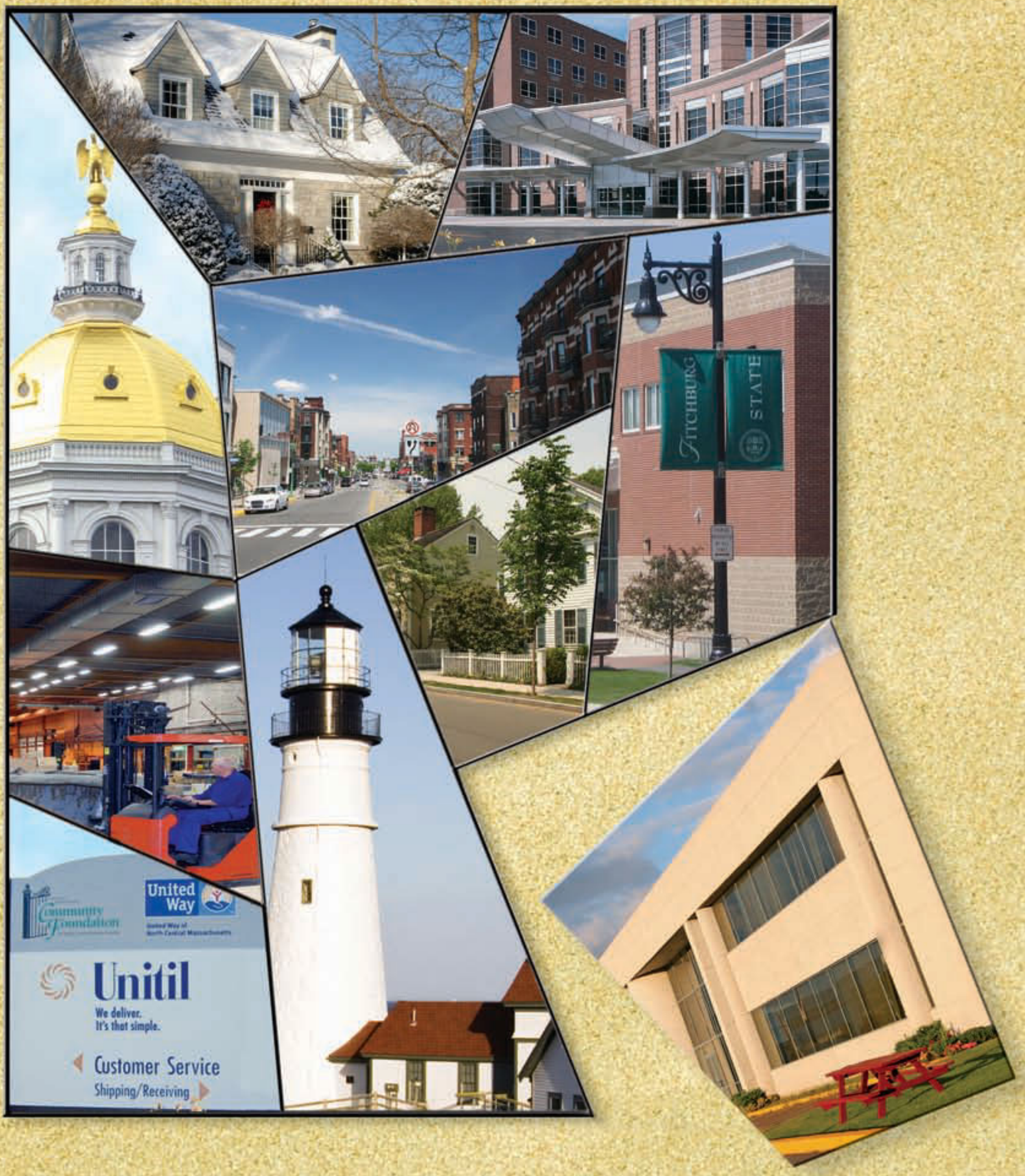
Direct Registration

Direct Registration is available without charge to shareholders of record of the Company's Common Stock. The Direct Registration System is a service within the securities industry that allows shares to be held and tracked electronically, without having to retain a physical stock certificate. For additional information, please contact Computershare at:

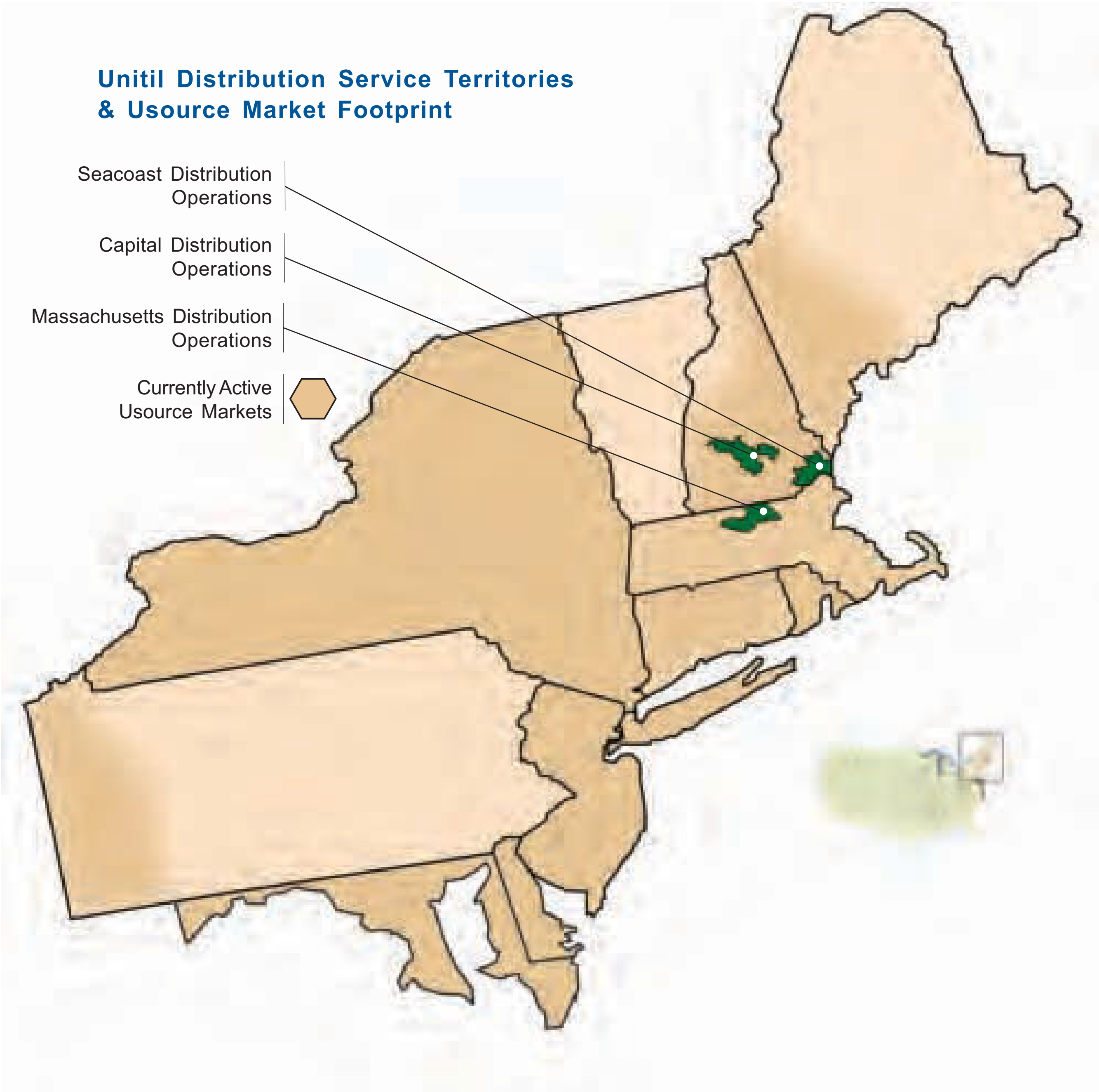
Mail: PO Box 43084
Providence, RI 02940-3084
Telephone: 800-935-9330
www.computershare.com/equiserve

Unitil Corporation • 6 Liberty Lane West • Hampton, NH 03842-1720
603-772-0775 • www.unitil.com

Unitil



Annual Report
2007



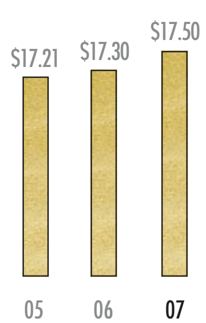
About the Company

Unitil (AMEX: UTL) is a public utility holding company with regulated utility subsidiaries providing electric distribution service in New Hampshire and electric and natural gas distribution service in Massachusetts. The Company also provides energy brokering and consulting services through its non-utility subsidiary, Usource. Additional information is available on line at www.unitil.com. Unitil's principal subsidiaries include Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc., and Usource.

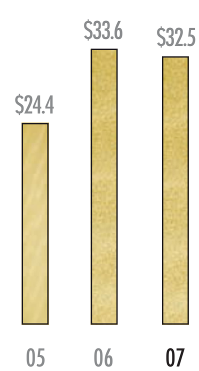
Financial Highlights

		2007		2006		2005
Financial Data (Millions)						
Total Operating Revenues	**$**	**262.9**	$	260.9	$	232.1
Total Operating Income	**$**	**18.5**	$	15.8	$	15.5
Earnings Applicable to Common	**$**	**8.6**	$	7.9	$	8.4
Capital Expenditures	**$**	**32.5**	$	33.6	$	24.4
Common Share Data						
Diluted Earnings per Share	**$**	**1.52**	$	1.41	$	1.51
Dividends Paid per Common Share	**$**	**1.38**	$	1.38	$	1.38
Book Value per Share (Year-end)	**$**	**17.50**	$	17.30	$	17.21
Market Price (Year-end)	**$**	**28.51**	$	25.35	$	25.16
Average Common Shares Outstanding (000's)		**5,672**		5,612		5,568
Operating Data						
Electric Distribution Sales (Millions of kWh)		**1,743.0**		1,751.5		1,790.4
Firm Gas Distribution Sales (Millions of therms)		**28.4**		26.4		24.3
Customers Served (Year-end)		**115,016**		114,387		113,593

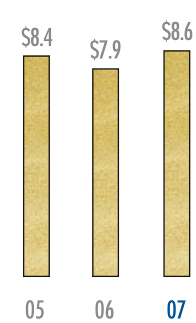
Book Value
Per Share
(Year-End)



Capital
Expenditures
(Dollars in Millions)



Earnings Applicable
to Common
(Dollars in Millions)



As a smaller player in the electric and natural gas industry, your Company has concentrated on opportunities appropriate to our scale to grow shareholder value and to improve the service we provide to our local communities and to our customers. We believe that, in part due to our size and the local proximity of our utility operations, we are able to respond more quickly and effectively to changing regulatory and public policy initiatives, to leverage new technology solutions that significantly improve productivity and customer service, and to implement organizational changes that improve performance. These advantages are key to our success in making prudent investments and taking initiatives that create value for both our shareholders and our customers. We first laid out this strategy for you in our 2004 Annual Report. Given the sometimes turbulent times in our industry over this period, following this path certainly has not been a straight route.

In 2004, we described the key initiatives we would pursue. These focused on our core business, including: controlling our costs through increases in productivity; managing our regulatory and rate setting process; growing Usource, our unregulated energy brokering subsidiary; and expanding our distribution operations through customer growth and potential acquisitions. I am pleased to tell you that we are beginning to see the real benefits of implementing this game plan. Below we describe the financial and operational performance we have been able to achieve and highlight the progress we are making in our strategic initiatives.

Our recently announced acquisition of Northern Utilities, a 52,000 customer natural gas distribution utility located in New Hampshire and Maine, from NiSource Inc. of Merrillville, Indiana, underscores our progress. This acquisition increases our customer base by more than 40% and further diversifies our asset mix between natural gas and electric energy delivery systems. The combination is a natural fit for Unitil. We expect to close on the purchase by the fourth quarter of 2008.

Financial Performance

The implementation of our strategic plan has provided a firm financial foundation for your Company. In 2007, we reported earnings per share of $1.52 compared to $1.41 last year, an increase of 8%. In addition, the total return to our shareholders, including the value of our dividend payments, was over 18% for 2007. We achieved these results despite record high energy prices, a related decline in average customer energy usage, and a softening economy. Our future challenge is to retain and grow these earnings on your behalf in a rapidly changing environment, while also helping our customers manage their energy costs and improve their energy efficiency.

Usource had a record year, generating $3.7 million in revenues — a 54% increase over 2006. Usource earned seven cents per share compared to a loss last year of three cents a share. We expect Usource to continue to contribute positively to the Company's bottom line, as it expands its geographical reach and works with new channel partners, including demand response firms and regional business associations.

Electric usage by our New Hampshire and Massachusetts electric distribution customers was down 0.5% in 2007 compared to 2006, due to cooler summer weather, energy conservation, and a slowing economy. Our natural gas distribution customers increased usage in 2007 by 7.6%, due principally to seasonably cold weather and expanded gas usage by industrial customers.

In spite of the sales decline, our electric sales margin increased by $1.9 million compared with the prior year, as a result of higher average delivery rates in 2007 compared to 2006. Our natural gas sales margin increased by $2.0 million for this same period, reflecting higher sales, as well as the effect of new natural gas distribution rates approved and implemented in 2007. In August 2007, we filed for an increase in electric distribution rates in Massachusetts. We expect a decision on our proposal by the end of the first quarter of 2008.

Operations

Our operational performance in 2007 continued to reflect the benefits of the investments we have been making in our systems and our technology. Electric reliability, one of the most visible performance metrics, exceeded our benchmarks for the year. Our safety record and our response time for natural gas odor calls also exceeded targets. Natural gas leak frequency

has declined significantly, primarily as a result of our investments in cast iron and bare steel replacement. Our customer service and satisfaction survey results continue to far outpace national benchmarks.

We also maintained top performance in operating costs per customer. In 2007 we completed the replacement of the traditional people-intensive meter reading technology with an advanced metering infrastructure utilizing a power-line carrier communication technology. This project, the largest single capital investment in the Company's history, was completed on-time and on-budget. This system already has significantly increased our productivity, and the technology platform it creates promises future benefits for customers and shareholders.

Regulation

Early in 2008, with the final approval of an electric distribution rate increase for our Massachusetts subsidiary, we will have completed the resource-intensive process of obtaining regulatory approval to update our base distribution rates for new investment and changes in operating costs for all of our utility operations. Base rate increases test our internal resources and challenge our key external relationships. We believe we have done a good job managing this process and have achieved significant savings for our customers by managing our costs over this period.

During 2007, legislative and regulatory activity in support of energy efficiency and renewable resources reached a new level of intensity in Massachusetts, in New Hampshire, and at the federal level. Regulatory officials in both Massachusetts and New Hampshire initiated proceedings to consider alternative ratemaking structures which would decouple utility distribution revenues from sales. Such a policy would help to align utility ratemaking with federal and state energy policy priorities in support of energy efficiency and renewable resources, and could reduce the financial pressures that lead to more frequent base rate proceedings.

In 2007, New Hampshire adopted a Renewable Portfolio Standard (RPS) applicable to all retail suppliers of electricity, including distribution companies, thereby joining Massachusetts and a number of other states that have RPS programs in place. RPS requires companies to procure an increasing share of their electricity supply from renewable sources of various types, or make alternative compliance payments to the state at specified energy rates.

In 2008, we anticipate passage of a major energy bill in Massachusetts and the possibility of a major energy bill at the federal level. Massachusetts and New Hampshire are also both poised to join in a regional carbon cap-and-trade program pursuant to the Northeast Regional Greenhouse Gas Initiative. Both states began proceedings in 2007 to consider implementing the federal Energy Policy Act standards regarding smart metering and distributed generation interconnection, and this work is expected to continue in 2008. The New Hampshire Public Utilities Commission recently affirmed a commitment to Time of Use rates and will open proceedings to design and implement Time of Use rates for the state's utilities.

Your Company is an active participant in all of these legislative and regulatory initiatives. We believe that energy efficiency and the development of local energy resources — especially renewable fuels — are the most effective tools available in New England to directly influence the region's energy future. Increased deployment of energy efficiency and renewable energy sources offers long-term benefits in the form of improved energy costs and price volatility, economic development, lower pollution and global warming and, ultimately, enhanced energy security.

Rixon Photography

We have also consistently pointed out that traditional distribution utility ratemaking, which tends to reward utilities for increasing sales and penalize them for reductions in sales, is at odds with these policy priorities and needs to be re-aligned. Last year we began to explore the possibility of legislation in New Hampshire that would allow distribution utilities to invest in small-scale distributed energy resources, including energy efficiency, demand response, and renewable generation such as solar, wind, and combined heat and power. We believe that, over time, utility investments in these technologies may complement investments in distribution facilities to meet increasing peak demands. A bill has been introduced in 2008 with broad support that would authorize such investments and establish a process for distribution utilities to seek rate recovery for these types of investments, including an incentive rate of return.

Distribution Transformation

We have completed the installation of an Automated Metering Infrastructure (AMI). Some 117,000 electric and gas bills are now generated on the basis of electronic data acquired from the field and validated without physical meter reads. Estimated meter reads due to weather or other factors are no longer a problem, and the process of obtaining meter reads for property transfers is vastly simplified. We are beginning to explore the technical opportunities now available as a consequence of taking the leap to AMI — opportunities which offer additional value in terms of customer service and business process efficiencies.

Unitil also continues to make progress with the broader integration of electronic information systems, including AMI and geographical information systems (GIS). Integrating GIS tools throughout the engineering design process, facility construction, and distribution operations is vastly improving efficiency and accuracy in these key business functions. While these functions may be largely invisible to the customer, their impact on reliability, cost, and productivity is significant. Moreover, the capabilities provided by this integration process enable the Company and its employees to explore and implement additional enhancements and system-wide innovations faster and more effectively.

We see these developments as part of a fundamental transformation of the distribution utility business from a static, one-way power delivery function to a dynamic multi-functional system that integrates and processes customer energy needs, energy market inputs, energy flows, and information on a simultaneous basis. This is the future "smart grid" which will reflect the confluence of technological innovation, the penetration of distributed energy resources, and the evolution of communication modes and consumer choices. This transformation will be evolutionary. We intend to be part of this transformation.

Distribution Growth

High energy prices, the housing crisis, and economic uncertainty create challenges for Unitil's efforts to foster gas and electric customer growth in its service areas. However, we continue to see progress with in-territory growth of gas distribution sales, given favorable trends in comparative prices

of natural gas and competing fuels and the environmental advantages and convenience of natural gas. Relative to other parts of the country, New England as a whole — and parts of Unitil's service territory specifically — have a low penetration of gas for business applications and home heating, providing continued opportunity for growth.

With the recent announcement of our acquisition of Northern Utilities, and the associated pipeline company Granite State Gas Transmission, Inc., Unitil has also achieved a key milestone in fulfilling its growth objectives through acquisition of new service areas. Northern Utilities, with 52,000 customers located in 44 communities in eastern New Hampshire and southern Maine, is a unique fit with Unitil's existing distribution businesses. Portions of Northern Utilities' service territory overlap, or are contiguous with, Unitil's existing electric distribution service territory in New Hampshire. The acquisition significantly strengthens our gas operations, while adding customers in our existing and nearby service areas. It affirms our business commitment in New Hampshire, while extending our reach into Maine, and it brings to those customers Unitil's strong track record of efficiency and quality customer service.

Usource

Usource achieved another record year. The Company's energy brokering activities generated $3.7 million in revenues, a 54% increase over 2006. Usource contributed seven cents per share to Unitil's earnings in 2007, compared to a net loss last year of three cents per share. This success was built on Usource's efforts to retain and expand its impressive client list among large energy users throughout the Northeast, but also reflects its success with its channel partners. Significantly, Usource was able to expand the scope of a key channel relationship and create a successful aggregation program for small and medium-sized energy users.

Usource also began building relationships with a number of companies providing demand response services, allowing it to expand the range of services available to Usource clients while also offering energy brokerage services to an expanded pool of

large energy users. We expect Usource to continue to contribute to the Company's bottom line, as it expands its geographical reach and works with new channel partners.

Conclusion

Your Company had a full and exciting year in 2007. We do not underestimate the short-term economic challenges facing our industry and country, or the significance of the transformations we expect in our industry over the long term. Nor do we take lightly the challenge of fulfilling our agenda for 2008 and beyond. We have the vision, the plans, and the resources needed to meet these challenges and achieve our long-term goal of increasing earnings per share by 3% to 5% per year.

We hope you agree that we are making the most of our opportunities.

Robert G. Schoenberger
Chairman of the Board of Directors
President & Chief Executive Officer

February 19, 2008

This Annual Report contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity, and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

Shareholder Information

2008 Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at the office of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 17, 2008, at 10:30 a.m.

Investor Information

The Company's Transfer Agent, Computershare Trust Company, N.A. ("Computershare"), is responsible for all shareholder records, including stock transfer, the distribution of dividends, tax documents and proxy materials. Shareholder requests regarding these and other matters can be addressed by corresponding directly with Computershare at:

Mail: PO Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

For information about the Company and your investment, you may also call the Company directly, toll-free, at: 800-999-6501 and ask for the Shareholder Representative; or visit the Investor Relations page at www.unitil.com.

Shareholder Programs

Dividend Reinvestment Plan

A Dividend Reinvestment and Stock Purchase Plan is available to all holders of record of the Company's Common Stock. This Plan provides shareholders with an economical means to increase their investment in the Company each quarter by reinvesting their dividends without broker fees. For additional information or enrollment, please contact the Company or Computershare.

Dividend Direct Deposit

Dividend Direct Deposit Service is available without charge to shareholders of record of the Company's Common Stock. For further information or enrollment in this service, please contact the Company or Computershare.

Direct Registration

The Company's Common Stock is eligible for Direct Registration, which is available without charge to shareholders of record. The Direct Registration System is a service within the securities industry that allows shares to be held and tracked electronically, without having to retain a physical stock certificate. For additional information, please contact Computershare at:

Mail: PO Box 43084
Providence, RI 02940-3084
Telephone: 800-935-9330
www.computershare.com

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d)
OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	American Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes__ No_X__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes__ No_X__

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes_X_ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K [X]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes__ No_X__

Based on the closing price of June 30, 2007, the aggregate market value of common stock held by non-affiliates of the registrant was $151,539,461.

The number of common shares outstanding of the registrant was 5,756,795 as of February 12, 2008.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 17, 2008, are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2007
Table of Contents

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly-owned subsidiaries of Unitil:

Unitil Corporation Subsidiaries	State and Year of Organization	Principal Type of Business
Unitil Energy Systems, Inc. (UES)	NH - 1901	Retail Electric Distribution Utility
Fitchburg Gas and Electric Light Company (FG&E)	MA - 1852	Retail Electric & Gas Distribution Utility
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-regulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering and Advisory Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts. Unitil has two distribution utility subsidiaries, UES, which operates in New Hampshire and FG&E, which operates in Massachusetts (collectively referred to as the "retail distribution utilities"). Unitil's retail distribution utilities serve approximately 100,000 electric customers and 15,100 natural gas customers in their franchise areas. The retail distribution companies are local "pipes and wires" utility distribution companies with a combined investment in net utility plant of $248.9 million at December 31, 2007. Unitil's total revenue was $262.9 million in 2007. Earnings applicable to common shareholders for 2007 was $8.6 million. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

OPERATIONS

Electric Utility Operations

Unitil's electric utility operations are conducted through the retail distribution utilities, UES and FG&E. Revenue from Unitil's electric utility operations was $225.0 million for 2007. Earnings from electric utility operations were $7.3 million for the same 12-month period.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its franchise areas. As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities continue to deliver that supply of electricity over their distribution systems. Both UES and FG&E supply electricity to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

UES distributes electricity to approximately 72,200 customers in New Hampshire in the capital city of Concord as well as 12 surrounding towns and all or part of 16 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. UES' franchise areas consist of approximately 408 square miles. The state capital of New Hampshire is located within UES' franchise areas, and includes the executive, legislative and judicial branches and offices and facilities for all major state government services as well as several federal government facilities. In addition, UES' franchise areas are retail trading and recreation centers for the central and southeastern parts of the state. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics. UES' franchise areas include popular resort areas and beaches along the Atlantic Ocean, including the Hampton Beach recreational area. UES' 2007 retail electric operating revenue was $157.8 million, of which approximately 51.0% was derived from residential sales and 49.0% from commercial/industrial sales.

FG&E is engaged in the retail distribution of both electricity and natural gas in the city of Fitchburg and several surrounding communities. FG&E's franchise area encompasses approximately 170 square miles. Electricity is supplied and distributed by FG&E to approximately 27,800 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. FG&E's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. FG&E's 2007 retail electric operating revenue was $67.2 million, of which approximately 52.0% was derived from residential sales and 48.0% from commercial/industrial sales.

Gas Utility Operations

Natural gas is supplied and distributed by FG&E to approximately 15,100 retail customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

FG&E's 2007 gas operating revenue was $34.2 million, of which approximately 55.0% was derived from residential firm sales and 45.0% from commercial/industrial firm sales. Earnings from FG&E's gas utility operations were $1.0 million for 2007.

Seasonality

Natural gas sales in New England are seasonal, and the Company's results of operations reflect this seasonal nature. Accordingly, results of operations are typically positively impacted by gas operations during the five heating season months, from November through March. Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours.

Non-regulated and Other Non-Utility Operations

Unitil's non-regulated operations are conducted through Unitil Resources and its subsidiary Usource. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's non-regulated operations was $3.7 million in 2007. Earnings from Unitil's non-regulated operations were $0.3 million in 2007. Unitil's other non-utility subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries. The earnings of these other non-utility operations are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and is reported in Other segment income (for segment information, see Part II, Item 8, Note 9 herein). Net earnings from Unitil's other non-utility operations were zero in 2007 as earnings on the short-term investments and real property discussed above were offset by interest expense.

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)

RATES AND REGULATION

Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Public Utilities (MDPU), respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third party vendors. Most customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next three to five years, is $104.8 million as of December 31, 2007 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet (see Regulatory Assets table in Note 1.) Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

ELECTRIC POWER SUPPLY

The transition to retail choice required the divestiture of Unitil's existing power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility service. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the Independent System Operator – New England (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive retail suppliers. Retail choice has been successful for Unitil's largest customers. As of December 2007, 94, or 60%, of Unitil's largest New Hampshire customers representing 23% of total New Hampshire electric sales and 27, or 84%, of Unitil's largest Massachusetts customers representing 35% of total Massachusetts electric sales are purchasing their electric power supply in the competitive market. This represents an increase of 25 in the number of large customers, primarily in New Hampshire, participating in the competitive market as of December 2007 compared to December 2006. However, most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, are 12 months in duration and provide 50% of the supply requirements. The MDPU regularly investigates alternatives to its statewide procurement policy, which could lead to future changes in the procurement structure described above.

UES currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. UES procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three-months in duration for 100% of supply requirements. UES procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

Regional Transmission and Power Markets

FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the Regional Transmission Organization (RTO) in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDPU and NHPUC.

GAS SUPPLY

FG&E's natural gas customers have the opportunity to purchase their natural gas supply from third-party vendors, although most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E purchases natural gas from domestic and Canadian suppliers under contracts of one year or less, as well as from producers and marketers on the spot market. FG&E arranges for gas delivery to its city gate station or underground storage through its own long-term contracts with the Tennessee interstate pipeline. The suppliers do have the option to deliver to the city gate station or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG) trucked to each storage facility within FG&E's service territory.

Sources of Gas Supply
(Expressed as percent of total MMBtu of gas purchased)

	2007	2006	2005
Natural Gas:			
Domestic firm	**94.6%**	84.2%	84.8%
Canadian firm	**2.2%**	2.0%	3.4%
Domestic spot market	**2.3%**	11.0%	9.3%
Total natural gas	**99.1%**	97.2%	97.5%
Supplemental gas	**0.9%**	2.8%	2.5%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2007	2006	2005
Cost of gas purchased and sold per MMBtu	**$ 10.41**	$ 11.18	$ 10.83
Percent Increase (Decrease) from prior year	**(6.9%)**	3.2%	28.7%

FG&E has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2007, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site – FG&E continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary closure of the site. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, FG&E is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition FG&E has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

FG&E is in the process of developing long range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2007 and 2006 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of the site. A corresponding regulatory asset was recorded to reflect the future rate recovery for these costs. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

The Company's ultimate liability for future environmental remediation costs may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

EMPLOYEES

As of December 31, 2007, the Company and its subsidiaries had 291 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

There are approximately 85 employees represented by labor unions. These employees are covered by collective bargaining agreements, which expire May 31, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is *www.unitil.com*. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the American Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 12, 2008:

Name	Age	Position
Robert G. Schoenberger	57	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	48	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	45	Senior Vice President and Chief Operating Officer
Laurence M. Brock	54	Controller and Chief Accounting Officer
Todd R. Black	43	President, Usource
George R. Gantz	56	Senior Vice President, Customer Services and Communications, Unitil Service Corp.
George E. Long, Jr.	51	Vice President, Administration, Unitil Service Corp.

Raymond J. Morrissey	60	Vice President, Information Systems
Sandra L. Whitney	44	Corporate Secretary
Dr. Robert V. Antonucci	62	Director
David P. Brownell	64	Director
Michael J. Dalton	67	Director
Albert H. Elfner, III	63	Director
Edward F. Godfrey	58	Director
Michael B. Green	58	Director
Eben S. Moulton	61	Director
M. Brian O'Shaughnessy	64	Director
Charles H. Tenney, III	60	Director
Dr. Sarah P. Voll	65	Director

Robert G. Schoenberger has been Unitil's chairman of the board and chief executive officer since 1997, and Unitil's president since 2003. Prior to his employment with Unitil, he was president and chief operating officer of the New York Power Authority (state-owned utility operating 6000 Mw of generation and 1400 miles of high voltage transmission) from 1993 until 1997. He also serves as chairman and trustee of Exeter Health Resources, and as a director of SatCon Technology Corporation.

Mark H. Collin has been Unitil's senior vice president and chief financial officer since February 2003. Mr. Collin has served as Unitil's treasurer since 1998. Since 1992, he has been treasurer of UES and FG&E. Mr. Collin joined Unitil in 1988. Mr. Collin serves on the board of governors of New Hampshire Public Television.

Thomas P. Meissner, Jr. has been Unitil's senior vice president and chief operating officer since June 2005. Mr. Meissner served as Unitil's senior vice president, operations, from February 2003 through June 2005. Mr. Meissner joined Unitil in 1994 and served as Unitil's director of engineering from 1998 to 2003. From 1985 to 1994, he was employed by the Public Service Company of New Hampshire.

Laurence M. Brock has been Unitil's chief accounting officer and controller since June 2005. Mr. Brock joined Unitil in 1995 as vice president and controller, and is a Certified Public Accountant in the State of New Hampshire. Prior to his employment with Unitil, Mr. Brock served as corporate controller with a group of diversified financial services and manufacturing companies. Mr. Brock gained his public accounting experience with Coopers & Lybrand in Boston, Massachusetts.

Todd R. Black has been president of Usource since June 2003. He served as vice president, sales and marketing for Usource from 1998 to 2003. Prior to his employment with Unitil, he served as vice president, services delivery for Energy USA, the non-regulated subsidiary of Bay State Gas Company, from 1988 until 1998.

George R. Gantz has been Unitil's senior vice president, customer services and communications since January 2003. Mr. Gantz previously served as Unitil's senior vice president, communication and regulation from 1994 to 2003. Mr. Gantz joined Unitil in 1983.

George E. Long, Jr. has been Unitil's vice president, administration since February 2003. Mr. Long joined Unitil in 1994 and was director, human resources from 1998 to 2003. Prior to his employment with Unitil, Mr. Long was the director of compensation and benefits at Monarch Life Insurance Company from 1985 to 1994.

Raymond J. Morrissey has been Unitil's vice president, information systems since February 2003. From 1992 to 2003, he served as Unitil's vice president of customer service, and from 1991 to 1992, he was the general manager of Unitil's subsidiary, FG&E. Mr. Morrissey joined Unitil in 1985.

Sandra L. Whitney has been Unitil's corporate secretary and secretary of the board since February 2003. Ms. Whitney has been the corporate secretary of Unitil's subsidiary companies, FG&E, UES, Unitil Power, Unitil Realty and Unitil Service since 1994. Ms. Whitney joined Unitil in 1990.

Dr. Robert V. Antonucci has been president of Fitchburg State College since 2003. Dr. Antonucci was also president of the School Group of Riverdeep, Inc. from 2001 to 2003, and president and CEO of Harcourt Learning Direct and Harcourt Online College from 1998 to 2001. Dr. Antonucci also served as the Commissioner of Education for the Commonwealth of Massachusetts from 1992 to 1998. Dr. Antonucci also serves as a trustee of Eastern Bank.

David P. Brownell was a senior vice president of Tyco International Ltd. from 1995 until his retirement in 2003. He had been with Tyco since 1984. Mr. Brownell was also interim president of the University of New Hampshire Foundation.

Michael J. Dalton was Unitil's president and chief operating officer from 1984 until his retirement in 2003. Mr. Dalton is a member of the Industrial Advisory Board of the University of New Hampshire College of Engineering and Physical Sciences.

Albert H. Elfner, III was the chairman, from 1994, and chief executive officer, from 1995, of Evergreen Investment Management Company until his retirement in 1999. Mr. Elfner is also a director of NGM Insurance Company (NGM), as well as a member of the NGM Finance Committee.

Edward F. Godfrey was the executive vice president and chief operating officer of Keystone Investments, Incorporated from 1997 until his retirement in 1998. While at Keystone Investments, he was also a senior vice president, chief financial officer and treasurer from 1988 to 1996. Mr. Godfrey is also a director of VehiCare, LLC since 2006.

Michael B. Green has been the president and chief executive officer of Capital Region Health Care and Concord Hospital since 1992. Mr. Green is also a member of the adjunct faculty, Dartmouth Medical School, Dartmouth College. He also currently serves on the Board of the Foundation for Healthy Communities, is a director of the New Hampshire Hospital Association, a director of New Hampshire Business Committee for the Arts, a director of Merrimack County Savings Bank, including membership on the bank's investment and audit committees.

Eben S. Moulton has been the managing partner of Seacoast Capital Corporation since 1995. Mr. Moulton is also a director of IEC Electronics, a director of six private companies and a trustee of Colorado College.

M. Brian O'Shaughnessy has been the chairman of the board of Revere Copper Products, Inc. since 1988. Mr. O'Shaughnessy also served as chief executive officer and president of Revere from 1988 - 2007. Mr. O'Shaughnessy also serves on the board of directors of the Coalition for a Prosperous America, three copper industry trade associations, three manufacturing associations in New York State regarding energy-related issues, and the Economic Development Growth Enterprise of Mohawk Valley.

Charles H. Tenney, III has been director of Operations for Brainshift.com, Inc. since 2002. Mr. Tenney is also a director and treasurer of "The BrainShift Foundation". Mr. Tenney also served on the board of overseers of the Huntington Theater Company, Boston, Massachusetts from 2004 - 2006.

Dr. Sarah P. Voll was vice president, National Economic Research Associates, Inc. (NERA) from 1999 until her retirement in 2007. Dr. Voll was also a senior consultant at NERA from 1996 to 1999. Prior to her employment with NERA, Dr. Voll was a staff member at the New Hampshire Public Utilities Commission from 1980 – 1996.

INVESTOR INFORMATION

Annual Meeting
The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 17, 2008, at 10:30 a.m.

Transfer Agent
The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of stock certificates, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Computershare
P.O. Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

Investor Relations
For information about the Company and your investment, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at www.unitil.com; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available

- Internet Account Access is available at www.computershare.com.
- Dividend Reinvestment Plan:
  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Dividend Direct Deposit Service:
  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Direct Registration:
  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

Risks related to the regulation of our business could impact the rates we are able to charge, our costs and our profitability.

We are subject to comprehensive regulation by federal and state regulatory authorities, which significantly influences our operating environment and our ability to recover costs from our customers. In particular, we are regulated by the FERC and state regulatory authorities with jurisdiction over public utilities, including the NHPUC and the MDPU. These authorities regulate many aspects of our operations, including, but not limited to, construction and maintenance of facilities, operations, safety, issuance of securities, accounting matters, transactions between affiliates, the rates that we can charge customers and the rate of return that we are allowed to realize. Our ability to obtain rate adjustments to maintain our current rate of return depends upon regulatory action under applicable statutes, rules and regulations, and we cannot assure you that we will be able to obtain rate adjustments or continue receiving our current authorized rates of return. These regulatory authorities are also empowered to impose financial penalties and other sanctions on us if we are found to have violated statutes and regulations governing our utility operations.

We are unable to predict the impact on our operating results from the regulatory activities of any of these agencies. Although we have attempted to actively manage the rate making process and have had recent success in obtaining rate adjustments, we can offer no assurances as to future success in the rate making process. Despite our requests, these regulatory commissions have authority under applicable statutes, rules and regulations to leave our rates unchanged, grant increases or order decreases in such rates. They have similar authority with respect to the recovery of our electricity and natural gas supply costs incurred by UES and FG&E in their role as a "provider of last resort" for customers who do not contract with third-party suppliers, or whose third-party supplier fails to deliver. In the event that we are unable to recover these costs or recovery of these costs were to be significantly delayed, our operating results could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have an adverse effect on our operating results.

As a result of industry restructuring, we have a significant amount of certain stranded energy supply costs, which are subject to recovery in future periods.

The stranded costs resulting from the implementation of industry restructuring mandated by the states of New Hampshire and Massachusetts are recovered by us on a pass-through basis through periodically adjusted rates. Any unrecovered balance of purchased power or stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

Our power supply portfolio related stranded costs due to the electric industry restructuring in New Hampshire and Massachusetts for which regulatory approval has been obtained for recovery were approximately $42.0 million for FG&E and $30.7 million for UES as of December 31, 2007 (See total of $72.7 million on the Power Supply Buyout Obligations line of Regulatory Assets table of Note 1). Substantially all of FG&E's stranded costs relate to owned generation assets and power purchase agreements divested by FG&E under a long-term contract buy-out agreement. UES' stranded costs are attributable to the long-term power purchase agreements divested by Unitil Power under long-term contract buyout agreements. Because FG&E and Unitil Power remain ultimately responsible for purchase power payments underlying these long-term buyout agreements, FG&E and Unitil Power could incur additional stranded costs were they required to resell such divested entitlements prior to the end of their term for amounts less than the amounts agreed to under the existing long-term buyout agreements. We expect that any such additional stranded costs would be recovered from our customers, although such recovery would require approval from the MDPU or NHPUC, the receipt of which cannot be assured.

Our electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may negatively impact our customers and correspondingly our operating results and financial condition.

Our business is influenced by the economic activity of our franchise areas. The level of economic growth in our electric and natural gas distribution franchise areas directly affects our potential for future growth in our business. As a result, adverse changes in the economy may have negative effects on our revenues, operating results and financial condition.

Declines in the valuation of capital markets could require us to make substantial cash contributions to cover our pension obligations, which could negatively impact our financial condition. In addition, the recovery of certain pension obligations is subject to regulatory risks.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period.

The Company made cash contributions of $2.8 million, $2.5 million and $2.5 million to its pension plan in 2007, 2006 and 2005, respectively, which exceeded minimum funding requirements. If the valuation of capital markets were to significantly decline from current levels, we may be required to make cash contributions to our pension plans substantially in excess of the levels currently anticipated, which could adversely affect our financial condition.

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158) which requires companies to record on their balance sheets the funded status of their retirement benefit obligations (RBO). The Company has recognized a liability for the projected RBO of its plans and a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates. In the event that we are unable to recover these costs or recovery of these costs were to be significantly delayed, our operating results could be materially adversely affected. See Note 8 also.

Increases in interest rates could have a negative impact on our financial condition.

Our utility subsidiaries have ongoing capital expenditure requirements which they frequently fund by issuing short and long-term debt. Changes in interest rates do not affect interest expense associated with presently outstanding fixed rate long-term debt securities. However, changes in interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities that are issued. In addition, short-term debt borrowings are typically at variable rates of interest. As a result, changes in short-term interest rates will increase or decrease our interest expense associated with short-term borrowings. Increases in interest rates generally will increase our borrowing costs and could adversely affect our financial condition or results of operations.

Weather conditions may cause our sales to vary from year to year.

Our utility operating sales vary from year to year, depending on weather conditions. We estimate that approximately 75% of our annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, particularly during the winter heating season. Our electric sales are generally less sensitive to weather than our gas sales, but may also be affected by weather conditions in both the winter and summer seasons.

We are a holding company and have no operating income of our own. Our ability to pay dividends on our common stock is dependent on dividends received from our subsidiaries and on factors directly affecting us, the parent corporation. We cannot assure you that our current annual dividend will be paid in the future.

We are a public utility holding company and we do not have any operating income of our own. Consequently, our ability to pay dividends on our common stock is dependent on dividends and other payments received from our subsidiaries, principally UES and FG&E. The ability of our subsidiaries to pay dividends or make distributions to us will depend on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of our subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by our subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of UES and FG&E and that may be contained in future debt agreements of our subsidiaries, if any;
- limitations that may be imposed by New Hampshire and Massachusetts state regulatory agencies.

In addition, we may incur indebtedness in the future. Before we can pay dividends on our common stock, we have to satisfy our debt obligations and comply with any statutory or contractual limitations.

Our current annual dividend is $1.38 per share of common stock, payable quarterly. However, our board of directors reviews our dividend policy periodically in light of the factors referred to above, and we cannot assure you of the amount of dividends, if any, that may be paid in the future.

Transporting and storing natural gas and supplemental gas supplies, as well as electricity, involve numerous risks that may result in accidents and other operating risks and costs.

Inherent in our electric and gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions, electrocutions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, and impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines, storage facilities and electric distribution equipment near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

Our business is subject to environmental regulation in all jurisdictions in which we operate and our costs of compliance are significant. Any changes in existing environmental regulation and the incurrence of environmental liabilities could negatively affect our results of operations and financial condition.

Our utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and the health and safety of our employees. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; imposition of remedial requirements; and even issuance of injunctions to ensure future compliance. Liability under certain environmental laws is strict, joint and several in nature. Although we believe we are in general compliance with all applicable environmental and safety laws and regulations, there can be no assurance that significant costs and liabilities will not be incurred in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, could result in increased environmental compliance costs. See “Environmental Matters” in the Part I, Item 1, and Note 5 of this report for further detail.

Catastrophic events could have a material adverse effect on our financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could have a material adverse effect on us, since they could inhibit our ability to continue providing electric and/or gas distribution services to our customers for an extended period, which is the principal source of our operating income.

Customers’ future performance under multi-year energy brokering contracts.

The Company’s non-regulated energy brokering business provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenues from this business are primarily derived from brokering fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts. The Company cannot guarantee customers’ future performance under multi-year energy brokering contracts.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2007, Unitil owned, through its retail distribution utilities: two operation centers, approximately 2,160 pole miles of local transmission and distribution overhead electric lines and 584 conduit bank miles of underground electric distribution lines, along with 49 electric substations, including three mobile electric substations. FG&E’s natural gas operations property includes a liquid propane gas plant, a liquid natural gas plant and 264 miles of underground gas mains. In addition, Unitil’s real estate subsidiary, Unitil Realty, owns the Company’s corporate headquarters building and the 12 acres on which it is located.

UES owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. UES’ 30 electric distribution substations, including a 5,000 kilovolt Ampere (kVA) mobile substation, constitute 214,037 kVA of capacity, which excludes capacity of spare transformers, for the transformation of electric energy from the 34.5 kV sub-transmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by UES or occupied by UES pursuant to a perpetual easement.

UES has a total of approximately 1,601 pole miles of local transmission and distribution overhead electric lines and a total of 406 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by UES without objection by the owners.

In the case of certain distribution lines, UES owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

The physical utility properties of UES, with certain exceptions, and its franchises are pledged as security under its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of UES are outstanding.

FG&E’s electric properties consist principally of 559 pole miles of local transmission and distribution overhead electric lines, 178 conduit bank miles of underground electric distribution lines and 19 transmission and distribution stations (including two mobile electric substations). The capacity of these substations totals 443,150 kVA, which excludes capacity of spare transformers.

FG&E owns a liquid propane gas plant and a liquid natural gas plant and the land on which they are located. FG&E also has 264 miles of underground steel, cast iron and plastic gas mains.

FG&E’s electric substations, with minor exceptions, are located on land owned by FG&E or occupied by FG&E pursuant to a perpetual easement. FG&E’s electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by FG&E without objection by the owners. FG&E leases its distribution operations center located in Fitchburg, Massachusetts.

The Company believes that its facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 4. Submission of Matters to a Vote of Security Holders

None

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's Common Stock is traded on the American Stock Exchange. As of December 31, 2007, there were 1,342 Common Shareholders of record.

Common Stock Data

Dividends per Common Share	**2007**	2006
1st Quarter	**$ 0.345**	$ 0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2007		2006	
Price Range of Common Stock	**High/Ask**	**Low/Bid**	High/Ask	Low/Bid
1st Quarter	**$27.30**	**$25.10**	$26.11	$24.59
2nd Quarter	**$28.40**	**$26.65**	$26.05	$23.70
3rd Quarter	**$31.73**	**$27.07**	$24.97	$23.80
4th Quarter	**$29.97**	**$25.75**	$26.09	$23.82

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

Equity Compensation Plan Benefit Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
KESOP (1)	---	N/A	---
Restricted Stock Plan (2)	---	N/A	106,365
Equity compensation plans not approved by security holders			
1998 Option Plan (3)	107,000	$27.13	---
Total	107,000	$27.13	106,365

NOTES: (also see Note 2 to the Consolidated Financial Statements)

(1) The KESOP was approved by shareholders in July 1989. Options were granted between January 1989 and November 1997. The last outstanding KESOP option was exercised in September 2007. No options remain outstanding and no additional options may be granted under the KESOP.

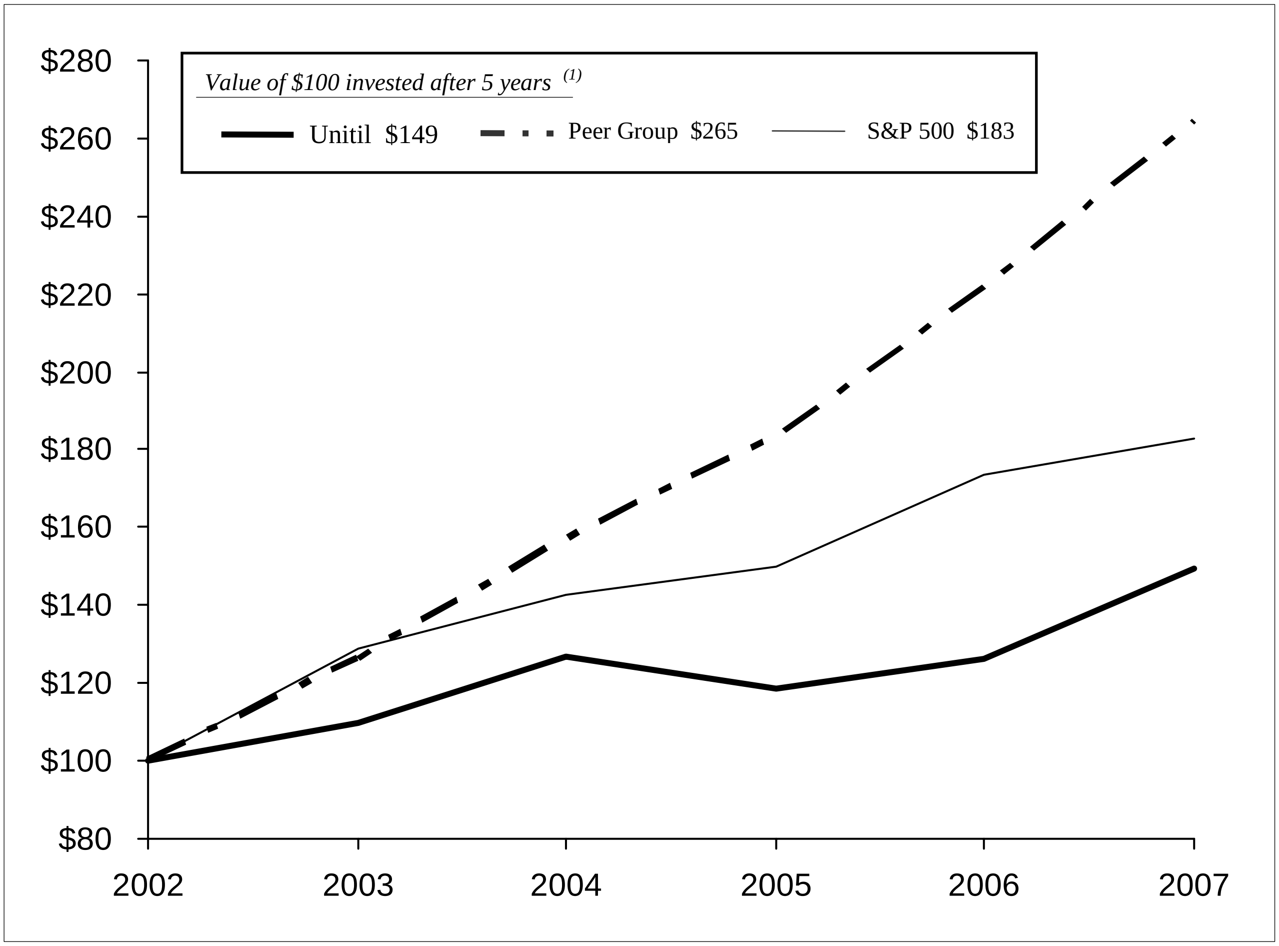
(2) The Restricted Stock Plan was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006; 9,020 shares of restricted stock were awarded to Plan participants in February 2007; 15,540 shares of restricted stock were awarded to Plan participants in February 2008.

(3) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the Option Plan were deregistered with the Securities and Exchange Commission. The Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the Option Plan. No further grants of options will be made thereunder.

Stock Performance Graph

The following graph compares Unitil Corporation's cumulative stockholder return since December 31, 2002 with the Peer Group index, comprised of the S&P Utility Index, and the S&P 500 index. The graph assumes that the value of the investment in the Company's common stock and each index (including reinvestment of dividends) was $100 on December 31, 2002.

Comparative Five-Year Total Returns



NOTES:

(1) The graph above assumes $100 invested on December 31, 2002, in each category and the reinvestment of all dividends during the five-year period. The Peer Group is comprised of the S&P Utility Index.

Unregistered Sales of Equity Securities and Uses of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2007.

The Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases. The Company expects to continue with these purchases indefinitely. Company repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
10/1/07 – 10/31/07	182	$29.10	182	n/a
11/1/07 – 11/30/07	---	---	---	n/a
12/1/07 – 12/31/07	---	---	---	n/a
Total	182	$29.10	182	n/a

Item 6. Selected Financial Data

For the Years Ended December 31, **(all data in millions except shares, % and per share data)**	**2007**	2006	2005	2004	2003
Consolidated Statements of Earnings:					
Operating Revenue	**$ 262.9**	$ 260.9	$ 232.1	$ 214.1	$ 220.7
Operating Income	**18.5**	15.8	15.5	15.2	15.4
Other Non-operating Expense (Income)	**0.2**	---	0.1	0.2	---
Income Before Interest Expense, net	**18.3**	15.8	15.4	15.0	15.4
Interest Expense, net	**9.6**	7.8	6.8	6.8	7.5
Net Income	**8.7**	8.0	8.6	8.2	7.9
Dividends on Preferred Stock	**0.1**	0.1	0.2	0.2	0.2
Earnings Applicable to Common Shareholders	**$ 8.6**	$ 7.9	$ 8.4	$ 8.0	$ 7.7
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 380.5**	$ 353.0	$ 325.0	$ 308.1	$ 288.7
Total Assets	**$ 474.6**	$ 483.4	$ 450.1	$ 457.0	$ 483.9
Capitalization:					
Common Stock Equity	**$ 100.4**	$ 97.8	$ 96.3	$ 94.3	$ 92.8
Preferred Stock	**2.1**	2.1	2.3	2.3	3.3
Long-Term Debt, less current portion	**159.6**	140.0	125.4	110.7	110.9
Total Capitalization	**$ 262.1**	$ 239.9	$ 224.0	$ 207.3	$ 207.0
Current Portion of Long-Term Debt	**$ 0.4**	$ 0.3	$ 0.3	$ 0.3	$ 3.3
Short-term Debt	**$ 18.8**	$ 26.0	$ 18.7	$ 25.7	$ 22.4
Capital Structure Ratios:					
Common Stock Equity	**38%**	41%	43%	46%	45%
Preferred Stock	**1%**	1%	1%	1%	2%
Long-Term Debt	**61%**	58%	56%	53%	53%
Earnings Per Share Data:					
Earnings Per Average Share	**$ 1.52**	$ 1.41	$ 1.51	$ 1.45	$ 1.58
Common Stock Data:					
Shares of Common Stock (000's)	**5,672**	5,612	5,568	5,525	4,896
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$1.38
Book Value Per Share (Year-End)	**$ 17.50**	$ 17.30	$ 17.21	$ 17.00	$16.87
Electric and Gas Sales:					
Electric Distribution Sales (Millions kWh)	**1,743.0**	1,751.5	1,790.4	1,742.1	1,717.7
Firm Natural Gas Distribution Sales (Millions Therms)	**28.4**	26.4	24.3	23.2	24.6

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through its two principal utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with an operating franchise in the southeastern seacoast and capital city areas of New Hampshire. FG&E is a combination gas and electric utility with an operating franchise in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 100,000 electric customers and 15,100 natural gas customers in their franchise areas. The retail distribution companies are local "pipes and wires" utilities with a combined investment in net utility plant of $248.9 million at December 31, 2007. Unitil's total revenue was $262.9 million in 2007. Earnings applicable to common shareholders for 2007 was $8.6 million. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Usource's total revenues were $3.7 million in 2007. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' future performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A. Risk Factors.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the three fiscal years ended December 31, 2007, 2006 and 2005 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report.

Net Income and EPS Overview

2007 Compared to 2006 - The Company's Earnings Applicable to Common Shareholders (Net Income) was $8.6 million for 2007, an increase of 9% over 2006 Net Income of $7.9 million. Earnings per common share were $1.52 for 2007, $0.11 per share higher than last year.

Earnings in 2007 reflect higher electric and gas sales margins, driven by higher rates and increased sales of natural gas, and improved profits from Usource, Unitil's non-regulated energy-brokering business. Partially offsetting these factors were higher operating expenses.

The following table presents the significant items (discussed below) contributing to the change in earnings per share in 2007 as compared to 2006:

2007 Earnings Per Share vs. 2006

	2006	**$ 1.41**
Electric Sales Margin		0.21
Gas Sales Margin		0.23
Usource Sales Margin		0.14
Operation & Maintenance Expense		(0.06)
Depreciation, Amortization & Other		(0.22)
Interest Expense, Net		(0.19)
	2007	**$ 1.52**

Unitil's total electric kWh sales decreased 0.5% in 2007 compared to 2006. Electric kWh sales to residential customers increased 0.4% in 2007 compared to 2006. The lower kWh sales in 2007 compared to 2006 were primarily driven by cooler summer weather this year, energy conservation by our customers and a slowing economy.

Unitil's total therm sales of natural gas increased 7.6% in 2007 compared to 2006. The increase in gas sales in 2007 reflects a colder winter heating season this year and higher natural gas sales to C&I customers. In 2007, natural gas sales to residential customers increased 4.1% compared to 2006 while sales to C&I customers increased 9.6% compared to 2006, primarily due to a special contract with a large industrial customer.

Total electric and gas sales margin increased $3.9 million in 2007 compared to 2006. This increase reflects higher gas and electric rates and increased sales of natural gas.

Total O&M expense increased $0.5 million, or 1.9%, in 2007 compared to 2006. This increase reflects higher employee and retiree compensation and benefit expenses of $0.8 million, higher bad debt expenses of $0.1 million and an increase in all other operating expenses of $0.2 million, net, offset by lower distribution utility operating expenses of $0.6 million.

Depreciation, Amortization, Taxes and Other expenses increased $2.2 million in 2007 compared to 2006 reflecting higher depreciation on normal utility plant additions in 2007 and income taxes on higher levels of pre-tax earnings in 2007 compared to 2006.

Interest Expense, Net increased $1.8 million in 2007 compared to 2006 reflecting higher debt outstanding, higher interest rates and higher interest expense recorded on reconciling mechanisms.

Usource, our non-regulated energy brokering business, recorded revenues of $3.7 million in 2007, an increase of $1.3 million over 2006. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

In 2007, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2008 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

2006 Compared to 2005 - The Company's Net Income was $7.9 million for 2006. Earnings per common share were $1.41 for 2006 compared to $1.51 for 2005. Earnings in 2006 reflect lower electric and gas sales. The lower sales in 2006 were primarily driven by milder weather compared to 2005. Earnings in 2006 also reflect higher operating and maintenance expenses and interest costs. Partially offsetting these factors was an increase in electric distribution rates in 2006 for Unitil's utility subsidiary in New Hampshire and increased gas delivery sales under a new contract with a large industrial customer in Massachusetts.

A more detailed discussion of the Company's 2007 and 2006 results of operations and a year-to-year comparison of changes in financial position are presented below.

Balance Sheet

The Company's investment in Net Utility Plant increased by $17.1 million in 2007 compared to 2006. This increase was due to capital expenditures related to UES' and FG&E's electric and gas distribution systems, including expenditures of approximately $6.6 million for the Company's Advanced Metering Infrastructure (AMI) project.

Regulatory Assets decreased $28.3 million in 2007 compared to 2006, primarily reflecting current year cost recoveries. A significant portion of this decrease is matched by a corresponding decrease of $19.9 million in Power Supply Contract Obligations.

Long-Term Debt increased $19.6 million in 2007 compared to 2006 reflecting the issuance and sale on May 2, 2007 by Unitil Corporation of $20.0 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors in the form of a private placement. Short-term Debt decreased $7.2 million in 2007 compared to 2006, as short-term borrowings were refinanced with the issuance of Senior Long-Term Notes, discussed above.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Unitil's total electric kWh sales decreased 0.5% in 2007 compared to 2006. Electric kWh sales to residential customers increased 0.4% in 2007 compared to 2006. The lower total kWh sales in 2007 compared to 2006 were driven by cooler summer weather this year, energy conservation by customers in response to higher overall energy prices and environmental concerns, and a slowing economy.

Unitil's total kWh sales decreased 2.2% in 2006 compared to 2005. This decrease reflects a decline in average energy usage per customer, primarily due milder weather in 2006 compared to 2005 and increased energy conservation by customers.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (millions)

	2007	2006	2005	2007 vs. 2006 Change kWh	2007 vs. 2006 Change %	2006 vs. 2005 Change kWh	2006 vs. 2005 Change %
Residential	**674.8**	672.2	688.3	2.6	0.4%	(16.1)	(2.3%)
Commercial / Industrial	**1,068.2**	1,079.3	1,102.1	(11.1)	(1.0%)	(22.8)	(2.1%)
Total	**1,743.0**	1,751.5	1,790.4	(8.5)	(0.5%)	(38.9)	(2.2%)

Electric Operating Revenues and Sales Margin – The following table details total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenues and Sales Margin (millions)

	2007	2006	2005	2007 vs. 2006 $ Change	2007 vs. 2006 % Change [1]	2006 vs. 2005 $ Change	2006 vs. 2005 % Change[1]
Electric Operating Revenue:							
Residential	**$ 114.7**	$ 105.9	$ 85.3	$ 8.8	3.9%	$ 20.6	10.4%
Commercial / Industrial	**110.3**	119.3	112.0	(9.0)	(4.0%)	7.3	3.7%
Total Electric Operating Revenue	**$ 225.0**	$ 225.2	$ 197.3	$ (0.2)	(0.1%)	$ 27.9	14.1%
Cost of Electric Sales:							
Purchased Electricity	**$ 165.4**	$ 167.3	$ 138.1	$ (1.9)	(0.8%)	$ 29.2	14.8%
Conservation & Load Management	**3.4**	3.6	3.8	(0.2)	(0.1%)	(0.2)	(0.1%)
Electric Sales Margin	**$ 56.2**	$ 54.3	$ 55.4	$ 1.9	0.8%	$ (1.1)	(0.6%)

[1] Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues decreased by $0.2 million, or 0.1%, in 2007 compared to 2006. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net decrease in Total Electric Operating Revenues in 2007 reflects lower Purchased Electricity costs of $1.9 million and lower C&LM revenues of $0.2 million, offset by higher sales margin of $1.9 million.

Purchased Electricity and C&LM revenues decreased $2.1 million, or 0.9%, of Total Electric Operating Revenues in 2007 compared to 2006, primarily reflecting an increase in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by higher electric commodity prices. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $1.9 million in 2007 compared to 2006. The improvement in electric sales margin reflects higher average distribution rates in 2007 compared to 2006, partially offset by lower sales volumes due to cooler summer weather this year, energy conservation by customers in response to higher overall energy prices and environmental concerns, and a slowing economy.

In 2006, Total Electric Operating Revenues increased by $27.9 million, or 14.1%, compared to 2005. The net increase in Total Electric Operating Revenues in 2006 reflects higher Purchased Electricity costs of $29.2 million, offset by lower sales margin of $1.1 million and lower C&LM revenues of $0.2 million. Purchased Electricity and C&LM revenues increased a net $29.0 million, or 14.7%, of Total Electric Operating Revenues in 2006 compared to 2005, reflecting higher electric commodity prices.

Electric sales margin was lower by $1.1 million in 2006 compared to 2005, reflecting a decrease in revenue of $3.2 million related to the expiration of the Seabrook Amortization Surcharge (SAS) in late 2005. Absent the decrease in SAS revenues, electric sales margin increased $2.1 million in 2006 compared to 2005. The higher sales margin in 2006 primarily reflects the Company's approved base rate increase in New Hampshire of $2.7 million, partially offset by lower sales margin of $0.6 million resulting from a decline in average energy usage per customer, primarily due to significantly milder weather and energy conservation.

Gas Sales, Revenues and Margin

Therm Sales - Unitil's total therm sales of natural gas increased 7.6% in 2007 compared to 2006. The increase in gas sales in 2007 reflects a colder winter heating season this year and higher natural gas sales to C&I customers. In 2007, natural gas sales to residential customers increased 4.1% compared to 2006 while sales to C&I customers increased 9.6% compared to 2006, primarily due to a special contract with a large industrial customer.

Unitil's total therm sales of natural gas increased 8.6% in 2006 compared to 2005, due to a new gas transportation sales contract with a large industrial customer. Sales to residential customers decreased 10.9% in 2006 compared to 2005 due to a milder winter heating season in 2006 compared to the prior year. Sales to C&I customers increased 24.8% in 2006 compared to 2005. Absent the sales from the new contract, discussed above, sales to C&I customers were 10.4% lower in 2006 compared to 2005 primarily due to a milder winter heating season.

The following table details total therm sales for the last three years, by major customer class:

Therm Sales (millions)

				2007 vs. 2006		2006 vs. 2005	
	2007	**2006**	**2005**	**Change**	**Change %**	**Change**	**Change %**
Residential	**10.2**	9.8	11.0	0.4	4.1%	(1.2)	(10.9%)
Commercial / Industrial	**18.2**	16.6	13.3	1.6	9.6%	3.3	24.8%
Total	**28.4**	26.4	24.3	2.0	7.6%	2.1	8.6%

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenues and Sales Margin (millions)

				2007 vs. 2006		2006 vs. 2005	
	2007	**2006**	**2005**	**$ Change**	**% Change(1)**	**$ Change**	**% Change(1)**
Gas Operating Revenue:							
Residential	**$ 18.8**	$ 17.2	$ 18.1	$ 1.6	4.8%	$ (0.9)	(2.8%)
Commercial / Industrial	**15.4**	16.1	14.7	(0.7)	(2.1%)	1.4	4.3%
Total Gas Operating Revenue	**$ 34.2**	$ 33.3	$ 32.8	$ 0.9	2.7%	$ 0.5	1.5%
Cost of Gas Sales:							
Purchased Gas	**$ 21.3**	$ 22.4	$ 21.2	$ (1.1)	(3.3%)	$ 1.2	3.7%
Conservation & Load Management	**0.2**	0.2	0.3	---	---	(0.1)	(0.4%)
Gas Sales Margin	**$ 12.7**	$ 10.7	$ 11.3	$ 2.0	6.0%	$ (0.6)	(1.8%)

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $0.9 million, or 2.7%, in 2007 compared to 2006. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The increase in Total Gas Operating Revenues in 2007 reflects higher sales margin of $2.0 million, partially offset by lower Purchased Gas costs of $1.1 million.

Purchased Gas and C&LM revenues decreased $1.1 million, or 3.3%, of Total Gas Operating Revenues in 2007 compared to 2006, reflecting lower natural gas commodity prices and an increase in the amount of natural gas purchased by customers directly from third-party suppliers. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $2.0 million in 2007 compared to 2006 reflecting higher sales and new natural gas distribution rates approved and implemented in 2007.

In 2006, Total Gas Operating Revenues increased $0.5 million, or 1.5%, compared to 2005. The net increase in Total Gas Operating Revenues in 2006 reflects higher Purchased Gas costs of $1.2 million, offset by lower sales margin of $0.6 million and lower C&LM revenues of $0.1 million. Purchased Gas and C&LM revenues increased a net $1.1 million, or 3.3%, of Total Gas Operating Revenues in 2006 compared to 2005, reflecting higher gas commodity prices and higher unit sales during those periods.

Gas sales margin for 2006 decreased $0.6 million compared to 2005. This decline in gas sales margin was due to lower therm sales, which, absent the sales from the new contract were 10.8% lower in 2006 compared to 2005. The lower gas sales were primarily due to a milder winter heating season. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, reflecting a record warm winter heating season.

Operating Revenue - Other

Total Other Revenue increased $1.3 million in 2007 compared to 2006 and $0.4 million in 2006 compared to 2005. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (millions)

				2007 vs. 2006		2006 vs. 2005	
	2007	**2006**	**2005**	**$ Change**	**% Change**	**$ Change**	**% Change**
Usource	$ 3.7	$ 2.4	$ 2.0	$ 1.3	54.2%	$ 0.4	20.0%
Total Other Revenue	$ 3.7	$ 2.4	$ 2.0	$ 1.3	54.2%	$ 0.4	20.0%

Operating Expenses

Purchased Electricity – Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity decreased $1.9 million, or 1.1%, in 2007 compared to 2006. This decrease reflects lower electric kWh sales and an increase in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not affect earnings.

In 2006, Purchased Electricity expenses increased $29.2 million, or 21.1%, compared to 2005 due to higher electric commodity prices.

Purchased Gas – Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $1.1 million, or 4.9%, in 2007 compared to 2006. The decrease in Purchased Gas is attributable to lower gas commodity prices and an increase in the amount of natural gas purchased by customers directly from third party suppliers, partially offset by increased therm sales. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

In 2006, Purchased Gas increased by $1.2 million, or 5.7%, compared to 2005, reflecting increased therm sales and higher gas commodity costs.

Operation and Maintenance (O&M) - O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. Total O&M expense increased $0.5 million, or 1.9%, in 2007 compared to 2006. This increase reflects higher employee and retiree compensation and benefit expenses of $0.8 million, higher bad debt expenses of $0.1 million and an increase in all other operating expenses of $0.2 million, net, offset by lower distribution utility operating expenses of $0.6 million.

In 2006, total O&M expense increased $1.2 million, or 4.9%, compared to 2005. This increase reflects higher retiree and employee compensation and benefit costs of $1.1 million and an increase in all other operating expenses of $0.1 million, net.

Conservation & Load Management - Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total Conservation & Load Management expenses decreased slightly, by $0.2 million, in 2007 compared to 2006. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total Conservation & Load Management expenses decreased $0.3 million in 2006 compared to 2005.

Depreciation and Amortization - Depreciation and Amortization expense increased $1.7 million, or 10.6% in 2007 compared to 2006 reflecting higher depreciation on normal utility plant additions in 2007.

In 2006, Depreciation and Amortization expense decreased $3.0 million, or 15.7%, compared to 2005, reflecting lower amortization on regulatory assets, including Seabrook Station, and lower depreciation rates on utility plant established in the Company's electric rate case settlement in New Hampshire, partially offset by depreciation on normal utility plant additions. The Company's regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Local Property and Other Taxes - Local Property and Other Taxes increased by $0.1 million, or 1.8%, in 2007 compared to 2006. This increase was due to higher local property tax rates on higher levels of utility plant in service and higher payroll taxes.

In 2006, Local Property and Other Taxes increased by $0.2 million, or 3.8% compared to 2005. This increase was due to higher local property tax rates on higher levels of utility plant in service and higher payroll taxes.

Federal and State Income Taxes - Federal and State Income Taxes increased by $0.2 million in 2007 compared to 2006 due to higher pre-tax operating income in 2007 compared to 2006.

Federal and State Income Taxes were essentially flat in 2006 compared to 2005 due to lower pre-tax operating income in 2006 compared to 2005 offset by a higher effective tax rate in 2006 related to the Company's former abandoned property investment in Seabrook Station, discussed above.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) increased by $0.2 million in 2007 compared to 2006. This change reflects the recognition in 2006 of a gain on the sale of land and timber harvest revenue.

Other Non-operating Expenses (Income) improved to income of $19,000 in 2006 compared to an expense of $147,000 in 2005, due to the gain discussed above.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated (See Note 3).

In 2007, Total Interest Expense, net, rose by $1.8 million compared to 2006. This increase principally reflects the issuance of new long-term debt by Unitil on May 2, 2007. Unitil issued and sold $20 million of Senior Long-Term Notes at a coupon rate of 6.33%, through a private placement to institutional investors. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries. The resulting reduction in average daily short-term bank borrowings lowered short-term interest expense for the year which partially offset the increase in long-term interest expense.

In 2006, Total Interest Expense, net, increased by $1.0 million compared to 2005. Interest expense on long-term borrowings increased due to the issuance of new fixed rate long-term debt. Unitil's New Hampshire subsidiary, UES, issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. In December 2005, Unitil's Massachusetts utility subsidiary, FG&E, issued $15 million of unsecured long-term notes to institutional investors at an interest rate of 5.90%. The proceeds from these long-term financings were used principally to finance utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. Interest expense on short-term debt increased compared to 2005 primarily due to higher variable short-term interest rates. These increases in interest expense were partially offset by an increase in interest income due to higher carrying charges on regulatory assets.

LIQUIDITY, COMMITMENTS AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. At December 31, 2007, Unitil had an aggregate of $30.0 million in unsecured revolving lines of credit with three banks. The Company anticipates that it will be able to secure renewal or replacement of some or all of its revolving lines of credit, in accordance with projected requirements. The Company had short-term debt outstanding through bank borrowings of $18.8 million and $26.0 million at December 31, 2007 and December 31, 2006, respectively. In addition, Unitil had approximately $4.6 million in cash at December 31, 2007. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets.

The maximum amount of short-term borrowings that may be incurred by Unitil and its subsidiaries has been subject to periodic approval by the Company's regulatory agencies. At December 31, 2007, Unitil had regulatory authorization to incur total short-term bank borrowings up to a maximum of $55 million, and UES and FG&E had regulatory authorizations to borrow up to a maximum of $16 million and $35 million, respectively. In 2007, UES and FG&E had average short-term debt outstanding of $7.9 million and $18.1 million, respectively.

Unitil and its subsidiaries are individually and collectively members of the Unitil Cash Pool. The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool Agreement allows for an efficient exchange of cash among Unitil and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on Unitil's actual interest costs from its banks under the revolving lines of credit. At December 31, 2007, all Unitil subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

On May 2, 2007, Unitil completed the sale of $20 million of Senior Long-Term Notes, through a private placement to institutional investors. The Notes have a term of 15 years maturity and a coupon rate of 6.33%. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries (see Note 3).

On September 26, 2006, UES issued and sold $15.0 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement (see Note 3). The proceeds from this long-term financing were used to repay short-term bank borrowings and permanently finance utility plant additions. In December 2005, FG&E issued and sold $15.0 million of 5.90% unsecured long-term notes under a debenture note structure (see Note 3). The proceeds were utilized to repay outstanding short-term indebtedness of FG&E and permanently finance utility plant additions. The Company expects to continue to be able to satisfy its external financing needs by utilizing additional short-term bank borrowings and to periodically replace short-term debt with long-term financings.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2007.

Significant Contractual Obligations (millions) as of December 31, 2007	**Total**	**Payments Due by Period: 2008**	**2009-2010**	**2011-2012**	**2013 & Beyond**
Long-term Debt	$ 160.0	$ 0.4	$ 0.8	$ 1.0	$ 157.8
Capital Leases	0.8	0.3	0.3	0.2	---
Operating Leases	2.8	0.5	1.0	0.9	0.4
Power Supply Contract Obligations – MA	42.0	8.1	16.7	16.6	0.6
Power Supply Contract Obligations – NH	30.7	11.9	14.4	1.2	3.2
Gas Supply Contracts	23.2	16.0	3.9	3.0	0.3
Total Contractual Cash Obligations	**$ 259.5**	**$ 37.2**	**$ 37.1**	**$ 22.9**	**$ 162.3**

The Company has material energy supply commitments that are discussed in Note 4. Cash outlays for the purchase of electricity and natural gas to serve our customers are subject to reconciling recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over collected cash over subsequent 6-12 month periods.

The Company also provides limited guarantees on certain electric supply contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2007 there are $6.5 million of guarantees outstanding and these guarantees extend through March 13, 2009.

Benefit Plan Funding

In 2007 and 2006, the Company and its subsidiaries made cash contributions to its pension plan in the amount of $2.8 million and $2.5 million, respectively. In 2007 and 2006, the Company and its subsidiaries contributed approximately $2.5 million and $2.2 million, respectively, to Voluntary Employee Benefit Trusts (VEBT). The Company and its subsidiaries expect to continue to make contributions to its pension plan and the VEBT's in future years in amounts consistent with the amounts recovered in retail distribution utility rates for these other postretirement benefit costs. (See Note 8).

Off-Balance Sheet Arrangements

The Company does not currently use, and is not dependent on the use of off-balance sheet financing arrangements, such as securitization of receivables, or obtaining access to assets or cash through special purpose entities or variable interest entities. The Company does have an operating lease agreement with a major financial institution. The operating lease is used to finance the Company's utility vehicles. (See Note 3).

Cash Flows

The tables below summarize the major sources and uses of cash (in millions) for 2007 compared to 2006.

	2007	2006
Cash Provided by Operating Activities	**$ 26.8**	$ 20.4

Cash Provided by Operating Activities – Cash Provided by Operating Activities was $26.8 million in 2007, an increase of $6.4 million compared to 2006. Sources of cash from Net Income were higher by $0.7 million compared to last year and sources of cash from Depreciation and Amortization rose by approximately $1.7 million. An additional $1.4 million of cash was utilized for Deferred Tax Provisions during the current year. Working capital related cash flows decreased $0.8 million in 2007 compared to 2006. Included in this change in working capital cash flows was an increase of $6.0 million year over year from Accrued Revenue, principally due to the recoveries of accrued revenues through reconciling cost recovery mechanisms. Sources of cash related to Deferred Restructuring Costs increased by $5.5 million in 2007 year over year, reflecting improvement in net cash flows for the collection of deferred costs related to utility industry restructuring. All other changes in cash flows from operating activities were a net increase of $0.7 million in sources of cash in 2007 compared to 2006.

	2007	2006
Cash (Used in) Investing Activities	**$ (32.5)**	$ (33.6)

Cash (Used in) Investing Activities - Cash (Used in) Investing Activities in 2007 was $32.5 million, a decrease of $1.1 million compared to 2006. Cash used in investing activities is primarily for capital expenditures related to UES' and FG&E's electric and gas distribution systems. Capital expenditures are projected to be $29.3 million in 2008, reflecting normal electric and gas utility plant additions. Capital expenditure projections are subject to changes during the fiscal year.

	2007	2006
Cash Provided by Financing Activities	**$ 5.7**	$ 14.6

Cash Provided by Financing Activities – Cash Provided by Financing Activities was $5.7 million in 2007, a decrease of $8.9 compared to 2006. Cash provided from short-term debt declined by $14.5 million in 2007, principally reflecting the repayment of short-term debt from the issuance of $20 million in Senior Long-Term Notes by Unitil in May 2007, described above. Proceeds from long-term debt issuances increased by $5.0 million in 2007 as compared to 2006, reflecting the issuance of $20 million in Unitil Notes in 2007 and the $15 million in UES Bond financings in 2006, described above. All other cash flows provided from other financing activities aggregated to a net change in cash flows of $0.6 million in 2007.

FINANCIAL COVENANTS AND RESTRICTIONS

The agreements under which the long-term debt of Unitil and its retail distribution utilities, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations (See Note 3).

The long-term debt and preferred stock of Unitil, UES and FG&E are privately held, and the Company does not issue commercial paper. For these reasons, the debt securities of Unitil and its subsidiaries are not publicly rated.

DIVIDENDS

Unitil's annualized common dividend was $1.38 per common share in 2007, 2006 and 2005. Unitil's dividend policy is reviewed periodically by the Board of Directors. Unitil has maintained an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2008 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

REGULATORY MATTERS

Overview – Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in the Company's franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, all of Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the providers of basic or default service energy supply. UES and FG&E purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the New Hampshire Public Utilities Commission (NHPUC) and Massachusetts Department of Public Utilities (MDPU), respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next three to five years, is $104.8 million as of December 31, 2007 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans (See Note 5).

FG&E – Electric Division – On August 17, 2007, FG&E filed an electric distribution rate increase of $3.3 million, which represents an increase of 4.7 percent over FG&E’s 2006 total electric operating revenue. The MDPU has suspended the effective date until March 1, 2008 in order to investigate the propriety of the Company’s request. Evidentiary hearings were held in November 2007 and briefing was completed in January 2008. The Company anticipates that it will receive a final order from the MDPU with an effective date for new electric rates of March 1, 2008.

FG&E – Gas Division – FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current retail distribution rates were approved by the MDPU in 2007. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On January 26, 2007, the MDPU approved a rate Settlement Agreement (Settlement) between FG&E and the Attorney General of Massachusetts for FG&E’s Gas Division. Under the Settlement, FG&E increased its gas distribution rates by $1.2 million on February 1, 2007, and an additional $1.0 million on November 1, 2007. The Settlement also included agreement on several other rate matters and service quality performance measures for the Company’s Gas Division in the areas of safety, customer service and satisfaction.

FG&E – Other – On June 22, 2007, the MDPU opened an inquiry into revenue decoupling, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility’s distribution revenues on sales. Revenue decoupling is adopted with the intent of removing the disincentive a utility has to administer and promote customer efforts to reduce energy consumption and demand or to install distributed generation to displace electricity delivered by the utility. The order included a straw proposal for a base revenue adjustment mechanism that severs the link between electric and gas companies’ revenues and sales, and instead, ties company revenues to the number of customers served. Many interested parties filed comments on the elements of the straw proposal and on revenue decoupling in general. Several parties also provided comments in panel hearings organized by the MDPU. Unitil filed comments generally supporting revenue decoupling and recommended modifications to the MDPU’s straw proposal. This matter remains pending.

UES – UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were approved by the NHPUC in 2006 under a Settlement Agreement with the NHPUC.

On June 22, 2007, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. This order set the framework for implementation of time based rates for utility provided default service. On August 31, 2007, the NHPUC issued an order on motion for rehearing, staying the June 22, 2007 order pending hearing and reconsideration of the issues. An order following hearing was issued on January 22, 2008 finding that it is appropriate to implement time-based metering standards and ordering that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes shall be determined in separate proceedings to be initiated by the Commission.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. Several parties attended the prehearing conference on June 18, 2007 and subsequent technical sessions. On July 30, 2007, the gas and electric utilities made baseline presentations designed to assist the parties in understanding current regulatory methods and the utilities’ assessment of existing incentives and barriers to energy efficiency investment. On November 7, 2007, the Commission hosted expert presentations about the potential of various regulatory approaches to promote energy efficiency. The proceeding remains open.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2007, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site – FG&E continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary closure of the site. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, FG&E is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition FG&E has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

FG&E is in the process of developing long range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2007 and 2006 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of the site. A corresponding regulatory asset was recorded to reflect the future rate recovery for these costs. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

The Company's ultimate liability for future environmental remediation costs may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

EMPLOYEES AND EMPLOYEE RELATIONS

As of December 31, 2007, the Company and its subsidiaries had 291 employees. The Company considers it relationships with employees to be good and has not experienced any major labor disruptions.

There are approximately 85 employees represented by labor unions. These employees are covered by collective bargaining agreements, which expire May 31, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDPU and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Retirement Benefit Obligations - The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees: the Unitil Corporation Retirement Plan (Pension Plan), a defined benefit pension plan covering substantially all of its employees; the Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) which provides health care and life insurance benefits to retirees; and the Unitil Corporation Supplemental Executive Retirement Plan (SERP), an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

The Company accounts for its pension and postretirement benefits in accordance with FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), SFAS No.

87, “Employers’ Accounting for Pensions” and SFAS No. 106, “Employers’ Accounting for Postretirement Benefits other than Pensions”. In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on these significant assumptions. SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized corresponding Regulatory Assets, to recognize the future collection of these obligations in electric and gas retail rates. (See Notes 1 and 8).

The Company’s reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements (See Note 8.)

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company’s current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company’s consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, “Accounting for Income Taxes” (SFAS No. 109) and under FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48), an interpretation of FAS 109.

Depreciation - Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company’s fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies - The Company’s accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2007, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company’s consolidated financial statements below.

Refer to “Recently Issued Accounting Pronouncements’ in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 7, "Income Taxes," Note 4, "Energy Supply," Note 8, "Benefit Plans," and Note 5, "Commitment and Contingencies," to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please also refer to Item 1A. “Risk Factors”.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 5.6%, 5.5% and 3.8% during 2007, 2006 and 2005, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Unitil Corporation and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the years ended December 31, 2007, 2006 and 2005. We also have audited Unitil Corporation and subsidiaries' internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unitil Corporation and subsidiaries as of December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Unitil Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Vitale, Caturano & Co. Ltd.

Boston, Massachusetts
February 8, 2008

CONSOLIDATED STATEMENTS OF EARNINGS

(Millions, except common shares and per share data)

Year Ended December 31,	**2007**	2006	2005
Operating Revenues:			
Electric	**$ 225.0**	$ 225.2	$ 197.3
Gas	**34.2**	33.3	32.8
Other	**3.7**	2.4	2.0
Total Operating Revenues	**262.9**	260.9	232.1
Operating Expenses:			
Purchased Electricity	**165.4**	167.3	138.1
Purchased Gas	**21.3**	22.4	21.2
Operation and Maintenance	**26.2**	25.7	24.5
Conservation & Load Management	**3.6**	3.8	4.1
Depreciation and Amortization	**17.8**	16.1	19.1
Provisions for Taxes:			
Local Property and Other	**5.6**	5.5	5.3
Federal and State Income	**4.5**	4.3	4.3
Total Operating Expenses	**244.4**	245.1	216.6
Operating Income	**18.5**	15.8	15.5
Other Non-Operating Expenses	**0.2**	---	0.1
Income Before Interest Expense	**18.3**	15.8	15.4
Interest Expense, net	**9.6**	7.8	6.8
Net Income	**8.7**	8.0	8.6
Less Dividends on Preferred Stock	**0.1**	0.1	0.2
Earnings Applicable to Common Shareholders	**$ 8.6**	$ 7.9	$ 8.4
Average Common Shares Outstanding (000's) - Basic	**5,659**	5,597	5,551
Average Common Shares Outstanding (000's) - Diluted	**5,672**	5,612	5,568
Earnings per Common Share – Basic and Diluted	**$ 1.52**	$ 1.41	$ 1.51

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS *(Millions)*

ASSETS

December 31,	**2007**	2006
Utility Plant:		
Electric	**$ 266.2**	$ 250.3
Gas	**67.8**	63.4
Common	**26.2**	25.3
Construction Work in Progress	**20.3**	14.0
Utility Plant	**380.5**	353.0
Less: Accumulated Depreciation	**131.6**	121.2
Net Utility Plant	**248.9**	231.8
Current Assets:		
Cash	**4.6**	4.6
Accounts Receivable – (Net of Allowance for Doubtful Accounts of $1.3 and $1.7)	**24.9**	22.5
Accrued Revenue	**12.7**	13.8
Refundable Taxes	**0.7**	---
Material and Supplies	**4.5**	4.5
Prepayments and Other	**1.5**	1.3
Total Current Assets	**48.9**	46.7
Noncurrent Assets:		
Regulatory Assets	**170.5**	198.8
Debt Issuance Costs, net	**2.8**	2.6
Other Noncurrent Assets	**3.5**	3.5
Total Noncurrent Assets	**176.8**	204.9
TOTAL	**$ 474.6**	$ 483.4

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (cont.) *(Millions)*

CAPITALIZATION AND LIABILITIES

December 31,		**2007**		2006
Capitalization:				
Common Stock Equity	**$**	**100.4**	$	97.8
Preferred Stock, Non-Redeemable, Non-Cumulative		**0.2**		0.2
Preferred Stock, Redeemable, Cumulative		**1.9**		1.9
Long-Term Debt, Less Current Portion		**159.6**		140.0
Total Capitalization		**262.1**		239.9
Current Liabilities:				
Long-Term Debt, Current Portion		**0.4**		0.3
Capitalized Leases, Current Portion		**0.3**		0.2
Short-Term Debt		**18.8**		26.0
Accounts Payable		**17.6**		19.8
Taxes Payable		**---**		0.9
Interest and Dividends Payable		**1.9**		1.6
Other Current Liabilities		**5.1**		4.6
Total Current Liabilities		**44.1**		53.4
Deferred Income Taxes		**33.4**		34.5
Noncurrent Liabilities:				
Power Supply Contract Obligations		**72.7**		92.6
Retirement Benefit Obligations		**48.2**		49.7
Environmental Obligations		**12.0**		12.0
Capitalized Leases, Less Current Portion		**0.5**		0.2
Other Noncurrent Liabilities		**1.6**		1.1
Total Noncurrent Liabilities		**135.0**		155.6
TOTAL	**$**	**474.6**	$	483.4

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Millions, except number of shares and par value)

December 31,	2007	2006
Common Stock Equity		
Common Stock, No Par Value (Authorized (000's) - 8,000 shares; Outstanding – 5,740 and 5,650 shares)	**$ 64.5**	$ 62.2
Stock Compensation Plans	**0.8**	1.3
Retained Earnings	**35.1**	34.3
Total Common Stock Equity	**100.4**	97.8
Preferred Stock		
UES Preferred Stock, Non-Redeemable, Non-Cumulative:		
6.00% Series, $100 Par Value	**0.2**	0.2
FG&E Preferred Stock, Redeemable, Cumulative:		
5.125% Series, $100 Par Value	**0.9**	0.9
8.00% Series, $100 Par Value	**1.0**	1.0
Total Preferred Stock	**2.1**	2.1
Long-Term Debt		
Unitil Corporation Senior Notes:		
6.33% Notes, Due May 1, 2022	**20.0**	---
UES First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15.0**	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0
FG&E Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19.0**	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**5.0**	5.3
Total Long-Term Debt	**160.0**	140.3
Less: Current Portion	**0.4**	0.3
Total Long-Term Debt, Less Current Portion	**159.6**	140.0
Total Capitalization	**$ 262.1**	$ 239.9

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS *(Millions)*

Year Ended December 31,	**2007**	2006	2005
Operating Activities:			
Net Income	**$ 8.7**	$ 8.0	$ 8.6
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**17.8**	16.1	19.1
Deferred Taxes	**(0.9)**	0.5	(0.2)
Changes in Current Assets and Liabilities:			
Accounts Receivable	**(2.4)**	1.1	(5.5)
Accrued Revenue	**1.1**	(4.9)	0.9
Accounts Payable	**(2.2)**	(0.8)	4.4
Taxes Payable / (Refundable)	**(1.6)**	0.9	0.6
All Other Current Assets and Liabilities	**0.5**	(0.1)	1.4
Deferred Restructuring Charges	**3.5**	(2.0)	(4.2)
Other, net	**2.3**	1.6	(1.0)
Cash Provided by Operating Activities	**26.8**	20.4	24.1
Investing Activities:			
Property, Plant and Equipment Additions	**(32.5)**	(33.6)	(24.4)
Cash (Used In) Investing Activities	**(32.5)**	(33.6)	(24.4)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**(7.2)**	7.3	(7.0)
Proceeds from Issuance of Long-Term Debt	**20.0**	15.0	15.0
Repayment of Long-Term Debt	**(0.3)**	(0.3)	(0.3)
Dividends Paid	**(7.9)**	(7.9)	(7.8)
Issuance of Common Stock	**1.5**	1.0	1.0
Retirement of Preferred Stock	**---**	(0.2)	---
Other, net	**(0.4)**	(0.3)	(0.4)
Cash Provided by Financing Activities	**5.7**	14.6	0.5
Net Increase (Decrease) in Cash	**---**	1.4	0.2
Cash at Beginning of Year	**4.6**	3.2	3.0
Cash at End of Year	**$ 4.6**	$ 4.6	$ 3.2
Supplemental Information:			
Interest Paid	**$ 12.2**	$ 10.7	$ 9.5
Income Taxes Paid	**$ 5.3**	$ 3.1	$ 4.5

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF
CHANGES IN COMMON STOCK EQUITY
(Millions, except number of shares)

	Common Shares	Stock Compensation Plans	Retained Earnings	Total
Balance at January 1, 2005	$ 59.9	$ 1.0	$ 33.4	$ 94.3
Net Income for 2005			8.6	8.6
Dividends on Preferred Shares			(0.2)	(0.2)
Dividends on Common Shares			(7.7)	(7.7)
Stock Compensation Plans	0.1	0.2		0.3
Issuance of 38,003 Common Shares	1.0			1.0
Balance at December 31, 2005	61.0	1.2	34.1	96.3
Net Income for 2006			8.0	8.0
Dividends on Preferred Shares			(0.1)	(0.1)
Dividends on Common Shares			(7.7)	(7.7)
Stock Compensation Plans	0.2	0.1		0.3
Issuance of 40,365 Common Shares	1.0			1.0
Balance at December 31, 2006	62.2	1.3	34.3	97.8
Net Income for 2007			8.7	**8.7**
Dividends on Preferred Shares			(0.1)	**(0.1)**
Dividends on Common Shares			(7.8)	**(7.8)**
Stock Compensation Plans	0.3			**0.3**
Exercised Stock Options – 42,437 Common Shares	1.0	(0.5)		**0.5**
Issuance of 38,303 Common Shares	1.0			**1.0**
Balance at December 31, 2007	$ **64.5**	**$ 0.8**	**$ 35.1**	$ **100.4**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil’s principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company’s two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES’ customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company’s corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company’s wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation - In accordance with current accounting pronouncements, the Company’s consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation.

Regulatory Accounting - The Company’s principal business is the distribution of electricity and natural gas by the Company-owned retail distribution utilities: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the Massachusetts Department of Public Utilities (MDPU) and UES is regulated by the New Hampshire Public Utilities Commission (NHPUC). Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, “Accounting for the Effects of Certain Types of Regulation” (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company’s principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company’s Regulatory Assets is provided below. Generally, the Company is currently receiving or being credited with a return on primarily all of its regulatory assets for which a cash outflow has been made. Generally, the Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. The Company must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDPU and NHPUC.

	December 31,	
Regulatory Assets consist of the following (millions)	**2007**	2006
Power Supply Buyout Obligations	**$ 72.7**	$ 92.6
Deferred Restructuring Costs	**30.5**	31.0
Generation-related Assets	**1.6**	2.5
Subtotal – Restructuring Related Items	**104.8**	126.1
Retirement Benefit Obligations	**35.1**	37.1
Income Taxes	**14.6**	19.1
Environmental Obligations	**13.1**	13.0
Other	**2.9**	3.5
Total Regulatory Assets	**$ 170.5**	$ 198.8

Massachusetts and New Hampshire have both passed utility industry restructuring legislation and the Company has filed and implemented its restructuring plans in both states. The Company is allowed to recover certain types of costs through ongoing assessments to be included in future retail rates. Based on the recovery mechanism that allows recovery of all of its stranded costs and deferred costs related to restructuring, the Company has recorded regulatory assets that it expects to fully recover in future periods.

The Company expects to continue to meet the criteria for the application of SFAS No. 71 for the distribution portion of its assets and operations for the foreseeable future. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met.

Cash – Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. Financial instruments that subject the Company to credit risk concentrations consist of cash and cash equivalents and accounts receivable. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. The Company believes it is not exposed to any significant credit risk on cash. Under the Independent System Operator – New England (ISO-NE) Financial Assurance Policy (Policy), Unitil's affiliates UES, FG&E and Unitil Power are required to provide assurance of their ability to satisfy their obligations to ISO-NE. Under this Policy, Unitil's affiliates provide cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2007 and 2006, the Unitil affiliates had deposited $2.5 million and $2.0 million, respectively to satisfy their ISO-NE obligations.

Goodwill and Intangible Assets – The Company does not have any goodwill recorded on its balance sheet as of December 31, 2007. There are no significant intangible assets recorded by the Company at December 31, 2007. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

Off-Balance Sheet Arrangements – As of December 31, 2007, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases and, in the Company's opinion, the amount of these transactions is not material.

Investments and Trading Activities – During the year, the Company does invest in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for book accounting purposes.

Derivatives – The Company enters into wholesale electric and gas energy supply contracts to serve its customers. The Company's policy is to review each contract and determine whether they meet the criteria for classification as derivatives under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), FASB Statement No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities", an amendment of SFAS No. 133 (SFAS No. 138) and / or FASB Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). As of December 31, 2007, the Company determined that none of its wholesale electric and gas energy supply contracts met the criteria for classification as a derivative instrument. Additionally, the Company may enter into interest rate hedging transactions with respect to existing indebtedness and anticipated debt offerings. As of December 31, 2007, the Company has not entered into any such transactions. However, should the Company enter into any such transactions in the future, its policy will be to review each transaction and determine whether it meets the criteria for classification as derivatives under SFAS No. 133, SFAS No. 138 and / or SFAS No. 149.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition - Non-regulated Operations - Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Retirement Benefit Obligations - The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees: the Unitil Corporation Retirement Plan (Pension Plan), a defined benefit pension plan covering substantially all of its employees; the Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) which provides health care and life insurance benefits to retirees; and the Unitil Corporation Supplemental Executive Retirement Plan (SERP), an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

The Company accounts for its pension and postretirement benefits in accordance with FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), FASB Statement No. 87, "Employers' Accounting for Pensions", (SFAS No. 87) and FASB Statement No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions", (SFAS No. 106). The Company has recognized Regulatory Assets, to recognize the future collection of these obligations in electric and gas retail rates (See Note 8).

Use of Estimates - The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company's policy is to record those estimates in accordance with the American Institute of Certified Public Accountants Statement of Position 94-6, "Disclosure of Certain Significant Risks and Uncertainties."

Commitments and Contingencies - The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5). SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2007, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below (See Note 5).

Utility Plant - The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 5.73%, 4.92% and 2.33% in 2007, 2006 and 2005, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company does not account separately for negative salvage, or cost of retirement obligations as defined in FASB Statement No. 143, "Accounting for Asset Retirement Obligations" and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations." The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. The Company is not mandated by any state or federal regulations or other commitments to retire assets other than those currently included in it mass asset depreciation base. At December 31, 2007 and December 31, 2006, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $16.2 million and $14.9 million, respectively.

Depreciation and Amortization – Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Depreciation provisions for Unitil's utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2007 – 4.29%, 2006 – 4.40% and 2005 – 4.69%.

Amortization provisions include the recovery, in 2005, of a portion of FG&E's former investment in Seabrook Station, a nuclear generating unit, in rates to its customers through the Seabrook Amortization Surcharge as ordered by the MDPU. FG&E's asset related to Seabrook Station became fully-amortized in the third quarter of 2005. In addition, FG&E is amortizing the balance of its unrecovered electric generating related assets, which are recorded as Regulatory Assets, in accordance with its electric restructuring plan approved by the MDPU (See Note 5).

Environmental Matters - The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. In the past three years, the Company has performed work on two environmental remediation projects, the Sawyer Passway MGP Site and the Former Electric Generating Station. The Company has or will recover substantially all of the cost of the work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2007, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 5, Commitments and Contingencies. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation - Unitil accounts for stock-based employee compensation currently using the fair value-based method (See Note 2).

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) and under FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109.

Dividends – The Company is currently paying a dividend at an annual rate of $1.38 per common share. The Company's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Other Recently Issued Pronouncements – In December 2007, the FASB issued FASB Statement No. 141 (Revised 2007), "Business Combinations" (SFAS No. 141R), effective prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141R establishes principles and requirements on how an acquirer recognizes and measures in its financial statements identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree, goodwill or gain from a bargain purchase and accounting for transaction costs. Additionally, SFAS No. 141R determines what information must be disclosed to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The Company will adopt SFAS No. 141R upon its effective date as appropriate for any future business combinations.

In February 2007, the FASB issued FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS No. 159), effective for fiscal years beginning after November 15, 2007. SFAS No. 159 includes an amendment of FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities." SFAS No. 159 permits entities to choose, at specified election dates, to measure eligible items at fair value and requires unrealized gains and losses on items for which the fair value option has been elected to be reported in earnings. The Company adopted SFAS No. 159 which had no impact on the Company's Consolidated Financial Position.

In September 2006, the FASB issued FASB Statement No. 157, "Fair Value Measurements", (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Certain requirements of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS No. 157 has been deferred for one year by the FASB. The Company adopted the sections of SFAS No. 157 which are effective for fiscal years beginning after November 15, 2007 and there was no impact on the Company's Consolidated Financial Statements. The Company does not expect that the adoption of the delayed sections of SFAS No. 157 will have an impact on the Company's Consolidated Financial Statements.

In February 2006, the FASB issued FASB Statement No. 155, "Accounting for Certain Hybrid Financial Instruments", (SFAS No. 155), which amends SFAS No.133 and FASB Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities", (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company's adoption of SFAS No. 155 did not have an impact on the Company's Consolidated Financial Statements.

Note 2: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

Dividend Reinvestment and Stock Purchase Plan - During 2007, the Company sold 38,303 shares of its Common Stock, at an average price of $27.44 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $1.0 million were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's Common Stock and cash payments in additional shares of the Company's Common Stock. During 2006 and 2005, the Company raised $1.0 million and $1.0 million, respectively, of additional common equity through the issuance of 40,365 and 38,003 shares, respectively, of its Common Stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired - During 2007, 2006 and 2005, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans - Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. The Company has adopted FASB Statement No. 123(R), "Accounting for Stock Based Compensation," and recognizes compensation costs at fair value at the date of grant. Details of the plans are as follows:

Restricted Stock Plan - On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company Common Stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided for in the Plan. Awards fully vest over a period of four years at a rate of 25% each year.

During the vesting period, dividends on restricted shares underlying the award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit.

Restricted shares issued for 2005 – 2007 in conjunction with the Plan are presented in the following table:

Issuance Date	Shares	Aggregate Market Value (millions)
3/8/05	10,900	$ 0.3
2/16/06	14,375	$ 0.4
2/9/07	9,020	$ 0.2

The compensation expense associated with the issuance of shares under the Plan is being accrued over the vesting period and was $0.4 million, $0.4 million and $0.3 million in 2007, 2006 and 2005, respectively, including amounts for tax gross-up. At December 31, 2007, there was approximately $0.7 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over a weighted average of approximately 2.2 years as the shares vest. There were 18,511 and 21,215 non-vested shares under the Plan as of December 31, 2007 and 2006, respectively. The weighted average grant date fair value of these shares was $25.95 and $26.34, respectively. There were no cancellations or forfeitures under the Plan during 2007. As shares vest, the Company's equity associated with those shares moves from "Stock

Compensation Plans" to "Common Shares" in the presentation of the Consolidated Changes in Common Stock Equity.

Unitil Corporation Key Employee Stock Option Plan – In the third quarter of 2007, the Company issued and sold 42,437 shares of its Common Stock, at a final average price of $10.70 per share, in connection with the exercise of stock options under the Unitil Corporation Key Employee Stock Option Plan (KESOP) which expired in 2007. As of December 31, 2007, there are no options remaining under the KESOP. Net proceeds of $0.5 million were used by the Company to reduce short-term borrowings.

The total compensation expenses recorded by the Company with respect to this plan were $57,000, $54,000 and $51,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

Share Option Activity of the "Unitil Corporation Key Employee Stock Option Plan" is presented in the following table:

	2007	2006	2005
Beginning Options Outstanding and Exercisable	**25,000**	25,000	25,000
Dividend Equivalents Earned – Prior Years	**15,388**	13,202	11,321
Dividend Equivalents Earned – Current Year	**2,049**	2,186	1,881
Options Exercised	**42,437**	----	----
Ending Options Outstanding and Exercisable	**---**	40,388	38,202
Weighted Average Exercise Price per Share	**$10.70**	$11.25	$11.89
Range of Option Exercise Price per Share	**$12.11-$18.28**	$12.11-$18.28	$12.11-$18.28
Weighted Average Remaining Contractual Life	**n/a**	0.9 years	1.9 years

Unitil Corporation 1998 Stock Option Plan - The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's Common Stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. This plan was terminated on January 16, 2003. There was no compensation expense associated with this plan in 2007, 2006 and 2005. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of options will be made under this plan.

There were 107,000 vested and exercisable options outstanding, with an weighted average exercise price of $27.13, at December 31, 2005, 2006 and 2007. There were no options granted or forfeited during those years.

The following summarizes certain data for the options outstanding at December 31, 2007:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$20.00-$24.99	34,500	$23.38	1.2 years
$25.00-$29.99	37,500	$25.88	3.1 years
$30.00-$34.99	35,000	$32.17	2.1 years
	107,000		

Preferred Stock

Unitil's two retail distribution companies, UES and FG&E, have preferred stock outstanding. At December 31, 2007, UES has a 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and FG&E has two series of Redeemable, Cumulative Preferred Stock outstanding, the 5.125% Series and the 8.00% Series.

FG&E is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, FG&E may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2007, 2006 and 2005 related to the annual redemption offer were $21,700, $22,000 and $11,400, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2007 is $117,000 per year.

On February 10, 2006, FG&E repurchased, canceled and retired 2,213 shares of its 8.00% series of Redeemable, Cumulative Preferred Stock at an aggregate par value of $221,300. FG&E used operating cash to effect this transaction.

Earnings Per Share

The following table reconciles basic and diluted earnings per share.

(Millions except shares and per share data)	**2007**	2006	2005
Earnings Available to Common Shareholders	**$ 8.6**	$ 7.9	$ 8.4
Weighted Average Common Shares Outstanding – Basic (000's)	**5,659**	5,597	5,551
Plus: Diluted Effect of Incremental Shares (000's)	**13**	15	17
Weighted Average Common Shares Outstanding – Diluted (000's)	**5,672**	5,612	5,568
Earnings per Share – Basic and Diluted	**$ 1.52**	$ 1.41	$ 1.51

Weighted average options to purchase 35,000, 72,500 and 72,500 shares of Common Stock were outstanding during 2007, 2006 and 2005, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Additionally, 2,030, 24,256 and 12,841 weighted average non-vested restricted shares for 2007, 2006 and 2005, respectively, were not included in the above computation because the effect would have been antidilutive.

Note 3: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowing arrangements. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery, vehicles and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Long-Term Debt Structure and Covenants - The agreements under which the long-term debt of Unitil and its retail distribution utilities, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

Unitil utilizes a debenture structure of long-term debt. The long-term debt of Unitil is issued under Unsecured Promissory Notes with negative pledge provisions. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Unitil to issue new long-term debt, the covenants of the existing long-term agreement(s), must be satisfied, including that Unitil have total funded indebtedness less than 70% of total capitalization, and earnings available for interest equal to at least two times the interest charges for funded indebtedness. Each future senior long-term debt issuance of Unitil will rank pari passu with all other senior unsecured long-term debt issuances. The Unitil agreement requires that if Unitil defaults on any other future long-term debt agreement(s), it would constitute a default under its present long-term debt agreement. Furthermore, the default provisions are triggered by the defaults of its Principal Utility Subsidiaries or certain other actions against subsidiary companies in the Unitil System.

UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. Substantially all the property of UES is subject to liens of indenture under which FMB's have been issued. In order to issue new FMB securities, the customary covenants of the existing UES Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities, and projected earnings available for interest charges equal to at least two times the annual interest requirement. The UES agreements further require that if UES defaults on any UES FMB securities, it would constitute a default for all UES FMB securities. The UES default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

FG&E utilizes a debenture structure of long-term debt. All of the long-term debt of FG&E is issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of FG&E's long-term debt ranks pari passu with its other senior unsecured long-term debt. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization, and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the UES agreements, FG&E agreements require that if FG&E defaults on any FG&E long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

The Unitil, UES and FG&E long-term debt instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets.

In addition, the Unitil, UES and FG&E long-term debt instruments and agreements contain certain restrictions on the payment of common dividends from Retained Earnings. On December 31, 2007, Unitil, UES and FG&E had unrestricted Retained Earnings of $18.4 million, $15.7 million and $7.1 million, respectively, available for the payment of common dividends. UES and FG&E pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil's common shareholders.

Debt Repayment and Sinking Funds - The total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $335,877, $310,136 and $286,368 in 2007, 2006 and 2005, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2007 is: 2008 - $363,755; 2009 - $393,946; 2010 - $426,643; 2011 - $462,055; and 2012 - $500,405, respectively.

Long-Term Debt Issuances - On May 2, 2007, Unitil completed the sale of $20 million of Senior Long-Term Notes, through a private placement to institutional investors. The Notes have a term of 15 years maturity and a coupon rate of 6.33%. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries.

On September 26, 2006 UES issued and sold $15 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement. The proceeds from this long-term financing were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings.

FG&E, through a private placement, consummated the issuance and sale on December 21, 2005 of $15 million of unsecured long-term notes to institutional investors. The notes have a term of 25 years and a coupon rate of 5.90%. The net proceeds were used to reduce FG&E's outstanding short-term indebtedness.

Fair Value of Long-Term Debt - The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at December 31, 2007 is estimated to be in a range of up to approximately $168 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

Interest Expense, net - Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's rate tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)	**2007**	2006	2005
Interest Expense			
Long-term Debt	**$ 11.1**	$ 9.5	$ 8.4
Short-term Debt	**1.1**	1.5	1.0
Regulatory Liabilities	**0.8**	0.3	0.2
Subtotal Interest Expense	**13.0**	11.3	9.6
Interest Income			
Regulatory Assets	**(2.9)**	(3.1)	(2.6)
AFUDC and Other	**(0.5)**	(0.4)	(0.2)
Subtotal Interest Income	**(3.4)**	(3.5)	(2.8)
Total Interest Expense, net	**$ 9.6**	$ 7.8	$ 6.8

Credit Arrangements

At December 31, 2007, Unitil had unsecured committed bank lines for short-term debt in the aggregate amount of $30.0 million with three banks for which it pays commitment fees. The weighted average interest rates on all short-term borrowings were 5.6%, 5.5% and 3.8% during 2007, 2006 and 2005, respectively. The Company had short-term debt outstanding through bank borrowings of approximately $18.8 million and $26.0 million at December 31, 2007 and December 31, 2006, respectively.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2007, 2006 and 2005 amounted to $433,000, $410,000 and $301,000 respectively. FG&E leases its operations facility in Fitchburg, Massachusetts under an operating lease, with a primary term through January 31, 2013. The lease agreement allows for three additional five-year renewal periods at the option of FG&E.

The following is a schedule of future operating lease payment obligations and future minimum lease payments under capital leases as of December 31, 2007:

Year Ending December 31, (000's)	**Operating Leases**	**Capital Leases**
2008	$ 524	$ 313
2009	521	169
2010	498	127
2011	442	81
2012	414	81
2013 – 2017	435	27
Total Payments	**$ 2,834**	**$ 798**

Guarantees

The Company also provides limited guarantees on certain energy contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2007 there are $6.5 million of guarantees outstanding and these guarantees extend through March 13, 2009. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

Note 4: Energy Supply

Electric Supply:

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive retail suppliers. Retail choice has been successful for Unitil's largest customers. As of December 2007, 94, or 60%, of Unitil's largest New Hampshire customers representing 23% of total New Hampshire electric sales and 27, or 84%, of Unitil's largest Massachusetts customers representing 35% of total Massachusetts electric sales are purchasing their electric power supply in the competitive market. This represents an increase of 25 in the number of large customers, primarily in New Hampshire, participating in the competitive market as of December 2007 compared to December 2006. However, most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

The transition to retail choice required the divestiture of Unitil's power supply arrangements and the procurement of load-following replacement supplies, which provided the flexibility for migration of customers to and from utility service. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO-NE markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

Power Supply Divestiture

Prior to May 1, 2003, UES purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, UES and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to UES ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, UES continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. Recovery of the contract release payments by UES from its retail customers has been approved by the NHPUC.

In connection with the implementation of retail choice, Unitil Power and FG&E divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next three to five years, is $104.8 million as of December 31, 2007 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet (see Regulatory Assets table in Note 1). Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, are 12 months in duration and provide 50% of the supply requirements. The MDPU regularly investigates alternatives to its statewide procurement policy, which could lead to future changes in the procurement structure described above.

UES currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. UES procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three-months in duration for 100% of supply requirements. UES procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

Regional Transmission and Power Markets

FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the Regional Transmission Organization (RTO) in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDPU and NHPUC.

Gas Supply:

FG&E's natural gas customers have the opportunity to purchase their natural gas supply from third-party vendors, although most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E purchases natural gas from domestic and Canadian suppliers under contracts of one year or less, as well as from producers and marketers on the spot market. FG&E arranges for gas delivery to its city gate station or underground storage through its own long-term contracts with the Tennessee interstate pipeline. The suppliers do have the option to deliver to the city gate station or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG) trucked to each storage facility within FG&E's service territory.

Sources of Gas Supply
(Expressed as percent of total MMBtu of gas purchased)

	2007	2006	2005
Natural Gas:			
Domestic firm	**94.6%**	84.2%	84.8%
Canadian firm	**2.2%**	2.0%	3.4%
Domestic spot market	**2.3%**	11.0%	9.3%
Total natural gas	**99.1%**	97.2%	97.5%
Supplemental gas	**0.9%**	2.8%	2.5%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2007	2006	2005
Cost of gas purchased and sold per MMBtu	**$ 10.41**	$ 11.18	$ 10.83
Percent Increase (Decrease) from prior year	**(6.9%)**	3.2%	28.7%

FG&E has available under firm contract 14,057 MMBtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Note 5: Commitments and Contingencies

Regulatory Matters

Overview – Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in the Company's franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, all of Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the providers of basic or default service energy supply. UES and FG&E purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next three to five years, is $104.8 million as of December 31, 2007 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E – Electric Division – FG&E provides electric distribution service to customers under unbundled distribution rates approved by the MDPU. Its current retail electric distribution rates were approved by the MDPU in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDPU. As of December 31, 2007, approximately 57 percent of FG&E's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large commercial and industrial (C&I) customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utility.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $32.1 million at December 31, 2007, and $33.3 million at December 31, 2006 and is expected to be recovered in FG&E's rates over the next three to five years. In addition, as of December 31, 2007, FG&E had recorded on its balance sheet $42.0 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

On August 17, 2007, FG&E filed an electric distribution rate increase of $3.3 million, which represents an increase of 4.7 percent over FG&E's 2006 total electric operating revenue. The MDPU has suspended the effective date until March 1, 2008 in order to investigate the propriety of the Company's request. Evidentiary hearings were held in November 2007 and briefing was completed in January 2008. The Company anticipates that it will receive a final order from the MDPU with an effective date for new electric rates of March 1, 2008.

FG&E – Gas Division – FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current retail distribution rates were approved by the MDPU in 2007. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On January 26, 2007, the MDPU approved a rate Settlement Agreement (Settlement) between FG&E and the Attorney General of Massachusetts for FG&E's Gas Division. Under the Settlement, FG&E increased its gas distribution rates by $1.2 million on February 1, 2007, and an additional $1.0 million on November 1, 2007. The Settlement also included agreement on several other rate matters and service quality performance measures for the Company's Gas Division in the areas of safety, customer service and satisfaction.

FG&E – Other – On June 22, 2007, the MDPU opened an inquiry into revenue decoupling, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is adopted with the intent of removing the disincentive a utility has to administer and promote customer efforts to reduce energy consumption and demand or to install distributed generation to displace electricity delivered by the utility. The order included a straw proposal for a base revenue adjustment mechanism that severs the link between electric and gas companies' revenues and sales, and instead, ties company revenues to the number of customers served. Many interested parties filed comments on the elements of the straw proposal and on revenue decoupling in general. Several parties also provided comments in panel hearings organized by the MDPU. Unitil filed comments generally supporting revenue decoupling and recommended modifications to the MDPU's straw proposal. This matter remains pending.

UES – UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were approved by the NHPUC in 2006 under the Settlement Agreement discussed below. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of December 31, 2007, approximately 74 percent of UES' electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large C&I customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utility.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery, including certain charges that remain subject to annual or periodic reconciliation or future review. As of December 31, 2007, UES had recorded on its balance sheets $30.7 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately three years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement (Agreement) resolving its electric distribution base rate case filed in November, 2005. The terms of the Agreement provided for an increase in base distribution rates of $2.3 million effective as of January 1, 2006. Additionally, the NHPUC has authorized two step increases in base distribution rates in accordance with the terms of the Agreement, related to utility plant additions in 2006, of approximately $0.4 million and $0.1 million annually, effective as of November 1, 2006 and May 1, 2007, respectively.

On June 22, 2007, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. This order set the framework for implementation of time based rates for utility-provided default service. On August 31, 2007, the NHPUC issued an order on motion for rehearing, staying the June 22, 2007 order pending hearing and reconsideration of the issues. An order following hearing was issued on January 22, 2008 finding that it is appropriate to implement time-based metering standards and ordering that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes shall be determined in separate proceedings to be initiated by the Commission.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. Several parties attended the prehearing conference on June 18, 2007 and subsequent technical sessions. On July 30, 2007, the gas and electric utilities made baseline presentations designed to assist the parties in understanding current regulatory methods and the utilities' assessment of existing incentives and barriers to energy efficiency investment. On November 7, 2007, the Commission hosted expert presentations about the potential of various regulatory approaches to promote energy efficiency. The proceeding remains open.

FERC – Wholesale Power Markets – FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the RTO in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England are performed on a regional basis. The ISO-NE Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDPU and NHPUC.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2007, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site – FG&E continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary closure of the site. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, FG&E is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition FG&E has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

FG&E is in the process of developing long range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2007 and 2006 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of the site. A corresponding regulatory asset was recorded to reflect the future rate recovery for these costs. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

The Company's ultimate liability for future environmental remediation costs may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

The following table shows the balances and activity in the Company's liability for Environmental Obligations for 2007. The liability for Environmental Obligations was initially recognized on the Company's Consolidated Balance Sheet at December 31, 2006.

ENVIRONMENTAL OBLIGATIONS

(Millions)	Balance at Beginning of Period	Provision	Payments / Reductions	Balance at End of Period
Year Ended December 31, 2007	$ 12.0	$ ---	$ ---	$ 12.0

Note 6: Bad Debts

FG&E and UES are authorized by the MDPU and NHPUC, respectively, to recover the costs of their energy commodity portion of bad debts through reconciling mechanisms. In 2006 and 2007, the Company recorded provisions for the energy commodity portion of bad debts of $1.7 million and $1.5 million, respectively. These provisions were recognized in Purchased Electricity and Purchased Gas expense as the associated electric and gas utility revenues were billed. Purchased Electricity and Purchased Gas costs are recovered from customers through periodic rate reconciling mechanisms. Prior to 2006, the commodity portion of bad debt expense was recognized in Purchased Electricity and Purchased Gas expense when the accounts were actually written off from accounts receivable.

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2005 – 2007.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	Additions: Provision	Additions: Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2007					
Electric	**$ 1,264,102**	**$ 1,434,356**	**$ 147,497**	**$ 1,840,407**	**$ 1,005,548**
Gas	**438,159**	**971,958**	**113,924**	**1,298,740**	**225,301**
Other	**34,526**	**34,659**	**---**	**33,644**	**35,541**
	$ 1,736,787	**$ 2,440,973**	**$ 261,421**	**$ 3,172,791**	**$ 1,266,390**
Year Ended December 31, 2006					
Electric	$ 342,791	$ 1,963,222	$ 136,399	$ 1,178,310	$ 1,264,102
Gas	110,031	1,325,650	134,802	1,132,324	438,159
Other	16,926	29,313	1,780	13,493	34,526
	$ 469,748	$ 3,318,185	$ 272,981	$ 2,324,127	$ 1,736,787
Year Ended December 31, 2005					
Electric	$ 392,824	$ 714,917	$ 116,290	$ 881,240	$ 342,791
Gas	89,602	721,171	116,366	817,108	110,031
Other	18,297	9,602	---	10,973	16,926
	$ 500,723	$ 1,445,690	$ 232,656	$ 1,709,321	$ 469,748

Note 7: Income Taxes

Federal Income Taxes were provided for the following items for the years ended December 31, 2007, 2006 and 2005, respectively:

	2007	2006	2005
Current Federal Tax Provision (000's):			
Operating Income	**$ 4,522**	$ 3,448	$ 3,671
Total Current Federal Tax Provision	**4,522**	3,448	3,671

Deferred Federal Tax Provision (000's)			
Accelerated Tax Depreciation	**(444)**	(656)	(668)
Abandoned Properties	**---**	---	(796)
Accrued Revenue	**(287)**	795	1,296
Retirement Benefit Obligations	**303**	271	299

Regulatory Assets and Liabilities	**(113)**	(5)	---
Other, net	**(243)**	(87)	(353)
Total Deferred Federal Tax Provision (Benefit)	**(784)**	318	(222)
Total Federal Tax Provision	**$ 3,738**	$ 3,766	$ 3,449

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2007, 2006 and 2005 are shown in the table below. In addition to the provisions for federal and state income taxes, the Company recorded provisions of $203,000, $211,000 and $179,000 in 2007, 2006 and 2005, respectively for state Business Enterprise taxes which are included in Local Property and Other Taxes on the consolidated statements of earnings.

Federal and State Tax Provisions (000's)	**2007**	2006	2005
Federal			
Current	**$ 4,522**	$ 3,448	$ 3,671
Deferred	**(784)**	318	(222)
Total Federal Tax Provision	**3,738**	3,766	3,449
State			
Current	**896**	337	844
Deferred	**(138)**	163	(18)
Total State Tax Provision	**758**	500	826
Total Provision for Federal and State Income Taxes	**$ 4,496**	$ 4,266	$ 4,275

The differences between the Company's provisions for Income Taxes, including the provision for Business Enterprise taxes, and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2007	2006	2005
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**5**	5	5
Utility Plant Differences	**(4)**	(4)	(6)
Other, Net	**---**	1	---
Effective Income Tax Rate	**35%**	36%	33%

Temporary differences which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	**2007**	2006
Accelerated Depreciation	**$ 19,776**	$ 25,232
Regulatory Assets / Liabilities & Mechanisms	**23,239**	23,592

Retirement Benefit Obligations	**(15,585)**	(17,644)
Contributions in Aid to Construction	**(4,651)**	(4,759)
Retirement Loss	**5,711**	4,945
Percentage Repair Allowance	**1,869**	1,994
Other	**3,024**	1,166
Total Deferred Income Tax Liabilities	**$ 33,383**	$ 34,526

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise's financial statements. FIN 48 prescribes a "more-likely-than-not" recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 applies to all tax positions related to income taxes subject to FAS 109. This includes tax positions considered to be routine as well as those with a high degree of uncertainty such as tax-advantaged transactions. FIN 48 effectively amends SFAS No. 5, such that all references to income taxes in SFAS No. 5 have been deleted and FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. FIN 48 creates a single model to address accounting for uncertainty in tax positions. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition, and classification and the cumulative affect of adopting FIN 48 may be recorded as an adjustment to retained earnings. The Company adopted FIN 48 as of January 1, 2007 and there was no impact on the Company's Consolidated Financial Statements.

The Company evaluated its tax positions at December 31, 2007 in accordance with FIN 48, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2004; December 31, 2005; and December 31, 2006. Income tax filings for the year ended December 31, 2007 are due March 15, 2008 but likely will be extended until September 15, 2008. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Note 8: Retirement Benefit Plans

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) – The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) – The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

	2007	2006	2005

Used to Determine Plan costs for years ended December 31:			
Discount Rate	**5.50%**	5.50%	6.00%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	9.00%	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2016**	2016	2013
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 690**	$ 683	$ 526
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$ (539)**	$ (530)	$ (413)

Used to Determine Benefit Obligations at December 31:			
Discount Rate	**6.00%**	5.50%	5.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2016	2016
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 6,282**	$ 6,381	$ 5,917
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$(5,030)**	$(5,091)	$(4,737)

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2007, 2006 and 2005, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost (NPBC). The Rate of Compensation Increase assumption used for 2007, 2006 and 2005 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The Expected Long-Term Rate of Return on plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on plan assets is based on target investment allocation of 60% in common stock equities and 40% in fixed income securities. The actual investment allocations are shown in the table below.

	Target Allocation	**Actual Allocation at December 31,**		
	2007	**2007**	2006	2005
Equity Securities	58-62%	**57%**	61%	60%
Debt Securities	38-42%	**43%**	39%	40%
Real Estate and Other	0-2%	**0%**	0%	0%
Total		**100%**	100%	100%

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2007. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan			PBOP Plan			SERP		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
Service Cost	**$ 1,968**	$ 1,800	$ 1,458	**$ 1,431**	$ 1,283	$ 993	**$ 163**	$ 148	$ 90
Interest Cost	**3,336**	3,153	3,085	**2,057**	2,028	1,795	**118**	103	80
Expected Return on Plan Assets	**(4,195)**	(3,775)	(3,404)	**(245)**	(194)	(41)	**---**	---	---
Prior Service Cost Amortization	**106**	107	107	**1,360**	1,360	1,401	**(2)**	(2)	(2)
Transition Obligation Amortization	**---**	---	---	**21**	21	21	**---**	17	17
Actuarial Loss Amortization	**1,345**	1,324	1,146	**70**	160	---	**44**	39	5
Sub-total	**2,560**	2,609	2,392	**4,694**	4,658	4,169	**323**	305	190
Amounts Capitalized and Deferred	**(873)**	(1,014)	(1,751)	**(2,033)**	(2,217)	(2,051)	---	---	---
NPBC Recognized	**$ 1,687**	$ 1,595	$ 641	**$ 2,661**	$ 2,441	$ 2,118	**$ 323**	$ 305	$ 190

The estimated amortizations related to Actuarial Loss and Prior Service Cost included in the Company's Retirement plan costs over the next fiscal year is $1.4 million, $1.4 million and less than $0.1 million for the Pension, PBOP and SERP plans, respectively.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2007, 2006 and 2005 was $2.6 million, $2.6 million and $2.4 million, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2007, 2006 and 2005 would have been $2.5 million, $2.8 million and $2.2 million respectively.

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan	PBOP Plan	SERP

	2007	2006	2007	2006	2007	2006
Change in Plan Assets:						
Plan Assets at Beginning of Year	**$ 49,527**	$ 44,535	**$ 3,052**	$ 2,304	**$ ---**	$ ---
Actual Return on Plan Assets	**2,480**	4,958	**89**	78	**---**	---
Employer Contributions	**2,800**	2,510	**2,500**	2,210	**72**	72
Benefits Paid	**(2,645)**	(2,476)	**(1,497)**	(1,540)	**(72)**	(72)
Plan Assets at End of Year	**$ 52,162**	$ 49,527	**$ 4,144**	$ 3,052	**$ ---**	$ ---
Change in PBO:						
PBO at Beginning of Year	**$ 62,027**	$ 58,586	**$ 38,107**	$ 37,528	**$ 2,179**	$ 1,910
Service Cost	**1,968**	1,800	**1,431**	1,283	**163**	148
Interest Cost	**3,336**	3,153	**2,057**	2,028	**118**	103
Benefits Paid	**(2,645)**	(2,476)	**(1,497)**	(1,540)	**(72)**	(72)
Actuarial (Gain) or Loss	**(257)**	964	**(2,115)**	(1,192)	**(244)**	90
PBO at End of Year	**$ 64,429**	$ 62,027	**$ 37,983**	$ 38,107	**$ 2,144**	$ 2,179
Funded Status: Assets vs PBO	**$ (12,267)**	$ (12,500)	**$ (33,839)**	$ (35,055)	**$ (2,144)**	$ (2,179)

In September 2006, the FASB issued SFAS No. 158 which requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets of $35.1 million and $37.1 million at December 31, 2007 and 2006, respectively, to recognize the future collection of these plan obligations in electric and gas retail rates.

In accordance with SFAS No. 132 “Employers Disclosures about Pensions and Other Postretirement Benefits,” the Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $55.1 million and $52.8 million as of December 31, 2007 and 2006, respectively. The ABO for the SERP was $0.6 million and $0.7million as of December 31, 2007 and 2006, respectively. For the PBOP Plan, the ABO and PBO are the same.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan’s liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company expects to contribute approximately $2.8 million to fund its Pension Plan in 2008.

The following table represents employer contributions and benefit payments ($000’s). There were no participant contributions.

	Pension Plan	PBOP Plan	SERP

	2007	2006	2005	2007	2006	2005	2007	2006	2005
Employer Contributions	**$ 2,800**	$ 2,510	$ 2,500	**$ 2,500**	$ 2,210	$ 2,500	**$ 72**	$ 72	$ 72
Benefit Payments	**$ 2,645**	$ 2,476	$ 2,404	**$ 1,497**	$ 1,540	$ 1,334	**$ 72**	$ 72	$ 72

The following table represents estimated future benefit payments ($000's).

	Estimated Future Benefit Payments		
	Pension	**PBOP**	**SERP**
2008	$ 2,940	$ 1,401	$ 71
2009	3,021	1,509	69
2010	3,224	1,670	66
2011	3,324	1,819	63
2012	3,432	1,942	61
2013 - 2017	$ 20,313	$ 11,361	$ 258

Employee 401(k) Tax Deferred Savings Plan --- The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. The Company matches contributions, with a maximum matching contribution of 3% of current compensation. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company Common Stock fund. Participants are 100% vested in contributions made on their behalf, once they have completed three years of service. The Company's share of contributions to the 401(k) Plan was $533,000, $528,000 and $503,000 for the years ended December 31, 2007, 2006, and 2005, respectively.

Note 9: Segment Information

Unitil reported four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil is engaged principally in the retail sale and distribution of electricity in New Hampshire and both electricity and natural gas service in Massachusetts through its retail distribution subsidiaries UES and FG&E. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty, Unitil Service and the holding company are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries' use. Unitil Resources and Usource are included in the Non-Regulated column below.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes and preferred stock dividends. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on cost allocation factors included in rate applications approved by the NHPUC and MDPU. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2007, 2006 and 2005 ($ Millions):

Year Ended December 31, 2007	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$ 225.0**	**$ 34.2**	**$ ---**	**$ 3.7**	**$ 262.9**
Interest Income	**2.8**	**0.1**	**0.5**	**---**	**3.4**
Interest Expense	**9.6**	**2.1**	**1.3**	**---**	**13.0**
Depreciation & Amortization Expense	**12.6**	**3.8**	**1.3**	**0.1**	**17.8**
Income Tax Expense (Benefit)	**3.8**	**0.4**	**0.1**	**0.2**	**4.5**
Segment Profit (Loss)	**7.3**	**1.0**	**---**	**0.3**	**8.6**
Segment Assets	**334.1**	**111.9**	**27.8**	**0.8**	**474.6**
Capital Expenditures	**26.2**	**6.1**	**0.2**	**---**	**32.5**
Year Ended December 31, 2006					
Revenues	$ 225.2	$ 33.3	$ ---	$ 2.4	$ 260.9
Interest Income	3.0	0.1	0.4	---	3.5
Interest Expense	9.5	1.1	0.6	0.1	11.3
Depreciation & Amortization Expense	11.2	3.5	1.3	0.1	16.1
Income Tax Expense (Benefit)	4.2	0.1	0.1	(0.1)	4.3
Segment Profit (Loss)	7.0	0.5	0.6	(0.2)	7.9
Segment Assets	346.7	113.1	22.7	0.9	483.4
Capital Expenditures	26.3	7.2	0.1	---	33.6
Year Ended December 31, 2005					
Revenues	$ 197.3	$32.8	$ ---	$ 2.0	$ 232.1
Interest Income	2.5	0.1	0.2	---	2.8
Interest Expense	8.1	0.9	0.6	---	9.6
Depreciation & Amortization Expense	14.5	3.1	1.4	0.1	19.1
Income Tax Expense (Benefit)	3.9	0.4	---	---	4.3
Segment Profit (Loss)	7.0	0.9	0.5	---	8.4
Segment Assets	328.2	98.2	22.5	1.2	450.1
Capital Expenditures	17.3	6.9	0.2	---	24.4

Note 10: Quarterly Financial Information (unaudited; Millions, except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006
Total Operating Revenues	**$77.8**	$70.7	**$59.0**	$60.3	**$61.8**	$66.2	**$64.3**	$63.7
Operating Income	**$ 4.7**	$ 3.9	**$ 4.3**	$ 3.4	**$ 3.9**	$ 3.8	**$ 5.6**	$ 4.7
Net Income Applicable to Common	**$ 2.6**	$ 2.0	**$ 1.7**	$ 1.4	**$ 1.6**	$ 1.8	**$ 2.7**	$ 2.7
	Per Share Data:							
Earnings Per Common Share	**$ 0.46**	$0.36	**$0.30**	$0.25	**$0.28**	$0.32	**$0.48**	$0.48
Dividends Paid Per Common Share	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of December 31, 2007. Based upon this evaluation, the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded as of December 31, 2007 that the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) are effective.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). In addition, management is required to report their assessment, including their evaluation criteria, on the design and operating effectiveness of the Company's internal control over financial reporting in this Form 10-K.

The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The Company's internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles. The Company's internal control over financial reporting includes policies and procedures which provide reasonable assurances that transactions are properly initiated, authorized, recorded, reported and disclosed, and provide reasonable assurances regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

During 2007, management conducted an assessment of the Company's internal control over financial reporting reflected in the financial statements, based upon criteria established in the "Internal Control – Integrated

Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on management's assessment, which included a comprehensive review of the design and operating effectiveness of the Company's internal control over financial reporting, management believes the Company's internal control over financial reporting is designed and operating effectively as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by Vitale, Caturano and Company, an independent registered public accounting firm. Their report appears in Item 8.

Item 9B. Other Information

None

PART III

Item 10. Directors and Executive Officers of the Registrant

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the 2007 Proxy Statement as filed with the Securities and Exchange Commission.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Compensation Discussion and Analysis" and "Compensation of Named Executive Officers" sections of the 2007 Proxy Statement as filed with the Securities and Exchange Commission.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the "Beneficial Ownership" and "As to the Election of Directors" sections of the 2007 Proxy Statement as filed with the Securities and Exchange Commission, as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions

None

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the 2007 Proxy Statement as filed with the Securities and Exchange Commission.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) - **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets - December 31, 2007 and 2006
- Consolidated Statements of Earnings for the years ended December 31, 2007, 2006, and 2005
- Consolidated Statements of Capitalization - December 31, 2007 and 2006
- Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006, and 2005
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2007, 2006, and 2005
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) - **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992 and April 30, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.4	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.5	Articles of Exchange of CECo, E&H, and the Company - Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984

3.6	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (FG&E) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.7	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, FG&E and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989 .
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002
4.2	FG&E Purchase Agreement dated March 20, 1992 for the 8.55% Senior Notes due March 31, 2004.	Exhibit 4.18 to Form 10-K for 1993
4.3	FG&E Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.4	FG&E Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.5	FG&E Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.6	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.7	FG&E Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.8	FG&E Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
<u>Exhibit Number</u>	<u>Description of Exhibit</u>	<u>Reference*</u>
4.9	Thirteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of September 26, 2006.	**
4.10	Unitil Corporation Note Purchase Agreement, dated as of May 2, 2007, for the 6.33% Senior Notes due May 1, 2022.	**
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4	Form of Severance Agreement between the Company and the	Exhibit 10.1 to

	persons listed at the end of such Agreement.	Form 10-Q for September 30, 2003
10.5	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 10-Q for September 30, 2003
10.6	Key Employee Stock Option Plan effective January 17, 1989.	Exhibit 10.56 to Form 8 dated April 12, 1989
10.7	Unitil Corporation Key Employee Stock Option Plan Award Agreement.	Exhibit 10.63 to Form 10-K for 1989
10.8	Unitil Corporation Management Performance Compensation Plan.	Exhibit 10.94 to Form 10-K/A for 1993
10.9	Unitil Corporation Supplemental Executive Retirement Plan effective as of January 1, 1987.	Exhibit 10.95 to Form 10-K/A for 1993
10.10	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.11	Unitil Corporation Management Incentive Plan.	Exhibit 10.13 to Form 10-K for 1998
10.12	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.13	Purchase and Sale Agreement For New Haven Harbor.	Exhibit 10.15 to Form 10-K for 1999
10.14	Labor Agreement effective June 1, 2000 between CECo and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.13 to Form 10-K for 2000
10.15	Labor Agreement effective June 1, 2000 between E&H and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.14 to Form 10-K for 2000
Exhibit Number	Description of Exhibit	Reference*
10.16	Labor Agreement effective June 1, 2000 between FG&E and The Utility Workers of America, AFL-CIO., Local Union No. B340, The Brotherhood of Utility Workers Council.	Exhibit 10.15 to Form 10-K for 2000
10.17	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.18	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.19	Unitil Corporation Tax Deferred Savings and Investment Plan – Trust Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2004
10.20	Employment Agreement effective as of November 1, 2006 by and between Unitil Corporation and Robert G. Schoenberger.	Exhibit 10.1 to Form 8-K dated September

		29, 2006
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** In accordance with Item 601(b)(4)(iii)(A) of Federal Securities Regulation S-K, the instrument defining the debt of the Registrant and its subsidiary, described above, has been omitted but will be furnished to the Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Unitil Corporation

Date February 12, 2008 By /s/ Robert G. Schoenberger
Robert G. Schoenberger
Chairman of the Board of Directors,
Chief Executive Officer and
President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Principal Executive Officer; Director	February 12, 2008
/s/ Mark H. Collin Mark H. Collin	Principal Financial Officer	February 12, 2008
/s/ Laurence M. Brock Laurence M. Brock	Principal Accounting Officer	February 12, 2008
/s/ Michael J. Dalton Michael J. Dalton	Director	February 12, 2008
/s/ Albert H. Elfner, III Albert H. Elfner, III	Director	February 12, 2008
/s/ M. Brian O'Shaughnessy M. Brian O'Shaughnessy	Director	February 12, 2008
/s/ Charles H. Tenney, III Charles H. Tenney, III	Director	February 12, 2008
/s/ Dr. Sarah P. Voll Dr. Sarah P. Voll	Director	February 12, 2008
/s/.Eben S. Moulton Eben S. Moulton	Director	February 12, 2008
/s/ David P. Brownell David P. Brownell	Director	February 12, 2008
/s/ Edward F. Godfrey Edward F. Godfrey	Director	February 12, 2008
/s/ Michael B. Green Michael B. Green	Director	February 12, 2008
/s/ Dr. Robert V. Antonucci Dr. Robert V. Antonucci	Director	February 12, 2008

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2007	2006	2005
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$ 8,746**	$ 8,033	$ 8,553
Less: Dividend Requirements on Preferred Stock	**136**	133	156
Net Income Applicable to Common Stock	**$ 8,610**	$ 7,900	$ 8,397
Average Number of Common Shares Outstanding - Basic	**5,659**	5,597	5,551
Dilutive Effect of Stock Options and Restricted Stock	**13**	15	17
Average Number of Common Shares Outstanding - Diluted	**5,672**	5,612	5,568
Earnings Per Share - Basic	**$ 1.52**	$ 1.41	$ 1.51
Earnings Per Share - Diluted	**$ 1.52**	$ 1.41	$ 1.51

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2007	2006	2005	2004	2003
(000's, except ratios)					
Earnings:					
Net Income, per Consolidated Statement of Earnings	**$ 8,746**	$ 8,033	$ 8,553	$ 8,226	$ 7,958
Federal and State Income Taxes included in Operations	**4,482**	4,266	4,275	4,206	3,551
Interest on Long-Term Debt	**10,919**	9,404	8,319	8,394	8,088
Amortization of Debt Discount Expense	**136**	112	104	98	82
Other Interest	**1,949**	1,675	1,046	629	1,070
Total	**$ 26,232**	$ 23,490	$ 22,297	$ 21,553	$ 20,749
Fixed Charges:					
Interest of Long-Term Debt	**$ 10,919**	$ 9,404	$ 8,319	$ 8,394	$ 8,088
Amortization of Debt Discount Expense	**136**	112	104	98	82
Other Interest	**1,949**	1,675	1,046	629	1,070
Pre-tax Preferred Stock Dividend Requirements	**213**	208	234	325	391
Total	**$ 13,217**	$ 11,399	$ 9,703	$ 9,446	$ 9,631
Ratio of Earnings to Fixed Charges	**1.98**	2.06	2.30	2.28	2.15

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has six wholly-owned subsidiaries, five of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The sixth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our report dated February 8, 2008, accompanying the December 31, 2007, 2006 and 2005 consolidated financial statements relating to the financial statements of Unitil Corporation and subsidiaries (the Company) and the effectiveness of the Company's internal control over financial reporting, included in the Annual Report of the Company on Form 10-K for the year ended December 31, 2007 in the Registration Statements of the Company on Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000).

/s/ Vitale, Caturano & Company Ltd.

Boston, Massachusetts
February 8, 2008

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2008

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2008

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2008

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

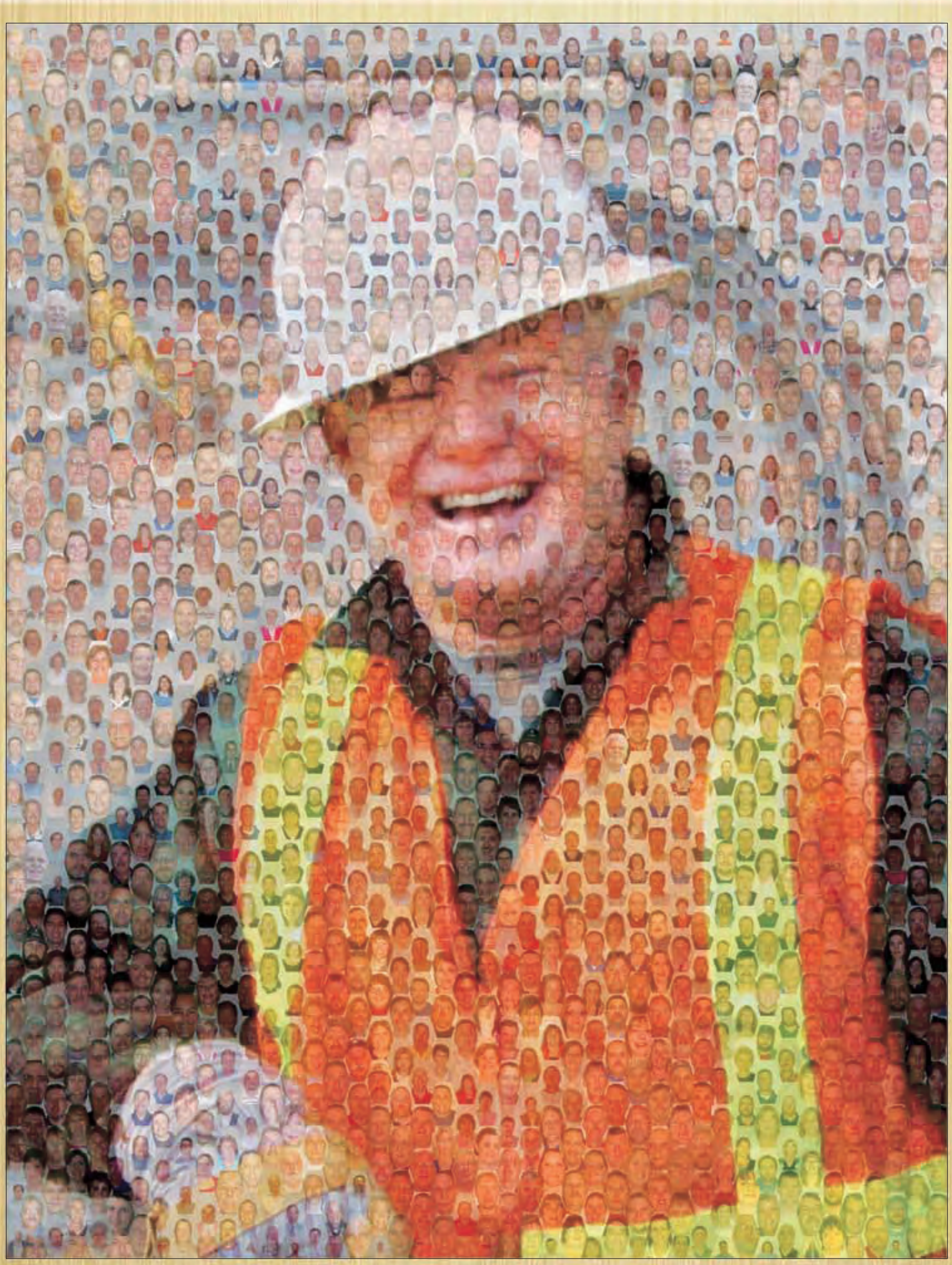
(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 12, 2008
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 12, 2008
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 12, 2008

Unitil Corporation • 6 Liberty Lane West • Hampton, NH 03842-1720
603-772-0775 • www.unitil.com

002CS-60849

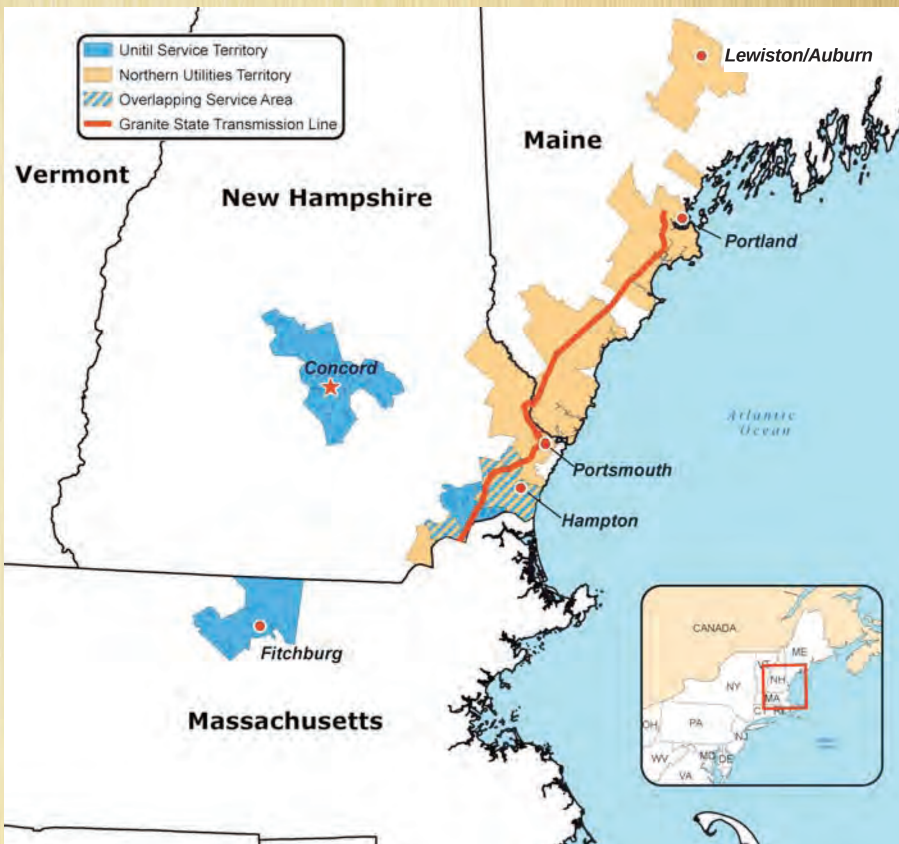


It's Our Employees.

Unitil

Annual Report 2008

Unitil Distribution Service Territories

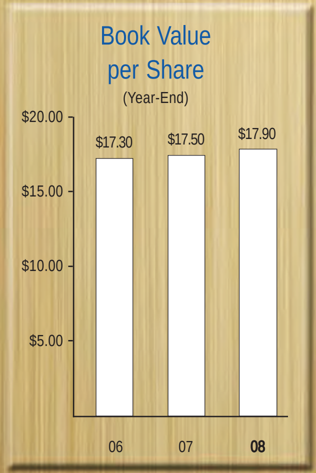


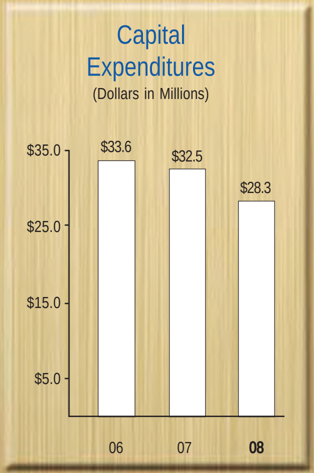
About the Company

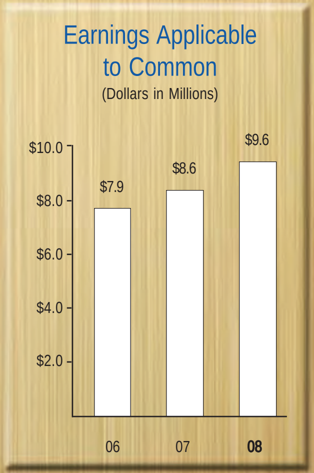
Unitil (NYSE: UTL) is a public utility holding company with utility subsidiaries providing electric and gas service in New Hampshire and Massachusetts and gas service in Maine. Unitil has approximately 430 employees and serves approximately 170,000 customers. Its utility subsidiaries include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc., and Granite State Gas Transmission, Inc. Its other main subsidiaries include Unitil Service Corp. and its non-regulated business segment doing business as Usource.

Financial Highlights*

		2008		2007		2006
Financial Data (Millions)						
Total Operating Revenues	**$**	**288.2**	$	262.9	$	260.9
Total Operating Income	**$**	**20.5**	$	18.5	$	15.8
Earnings Applicable to Common	**$**	**9.6**	$	8.6	$	7.9
Capital Expenditures	**$**	**28.3**	$	32.5	$	33.6
Common Share Data						
Diluted Earnings per Share	**$**	**1.65**	$	1.52	$	1.41
Dividends Paid per Common Share	**$**	**1.38**	$	1.38	$	1.38
Book Value per Share (Year-end)	**$**	**17.90**	$	17.50	$	17.30
Market Price (Year-end)	**$**	**20.65**	$	28.51	$	25.35
Average Common Shares Outstanding (000's)		**5,830**		5,672		5,612
Operating Data						
Electric Distribution Sales (Millions of kWh)		**1,695.9**		1,743.0		1,751.5
Firm Gas Distribution Sales (Millions of therms)		**47.2**		28.4		26.4
Customers Served (Year-end)		**169,602**		115,016		114,387







* *Financial Highlights reflect the acquisition on December 1, 2008, of Northern Utilities, Inc. and Granite State Gas Transmission, Inc.*

To Our Shareholders

2008 was a transformative year for your Company, culminating with the acquisition of Northern Utilities and Granite State Gas Transmission from NiSource. The transaction was a few years in the making and capitalized on our steady resolve and prudent pursuit of this attractive opportunity.

The acquisition nearly doubles the size of the Company, increasing our customer base to about 170,000 and diversifying our revenues and earnings between electric and gas operations. We now operate in the states of Maine, Massachusetts, and New Hampshire, and are uniquely positioned to seek new opportunities to expand on this electric and gas combination utility platform.

We closed on the acquisition on December 1, which allowed us to count the benefits of one month of the gas heating season in our 2008 gas sales margin. Notably, we secured regulatory approvals of the acquisition in three states in just eight months. We were also successful in putting together a credit-worthy acquisition financing in the most challenging financial market in generations.

We are well on our way to integrating these new operating subsidiaries into your Company. Since the acquisition is essentially a carve out of operating divisions of a larger Company, we are expanding our own capabilities – including the hiring of 65 new employees – to provide centralized administrative and professional services for these new operating subsidiaries through our shared utility services model. We will complete the transition of all major systems, including customer information, financial services and gas operations, in the first half of 2009. We expect to realize significant synergies of $5.6 million per year from this combination.

The acquisition has already produced benefits. In 2008 net income increased by 12% to a record $9.6 million over $8.6 million in 2007. Earnings per share increased to $1.65, $0.13 higher than last year, including the benefit of higher gas sales margins, due to the acquisitions. The Company paid annual dividends of $1.38, representing a continuous payment of quarterly dividends since Unitil was formed in 1985. We achieved these results in the most challenging economic environment that we have seen in a long time.

The acquisition and integration of these new utility subsidiaries into your Company has been a major challenge. Our employees have risen to this challenge and made extraordinary efforts in managing the complex and rigorous details associated with the acquisition, while continuing to provide high-quality operations and customer service for our existing utility business.

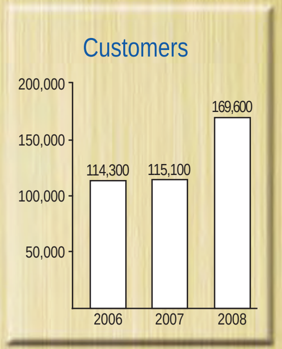
In the midst of all these activities, the New England region was hit by a major ice storm on the evening of December 11, 2008. The storm was a region-wide event with the worst-hit areas concentrated in our Fitchburg franchise area and southern and western New Hampshire. At the height of the storm, two-thirds of our customers were out of service. Crews from as far away as Tennessee, Ohio, and Michigan were brought in to help restore power. This was a very difficult time for the Company and its employees, our communities, and our customers, as it took 14 days for us to completely restore power. Power restoration times for utilities in the region ranged from 10 days to 21 days. The cost of the storm restoration effort is estimated at $10 million.

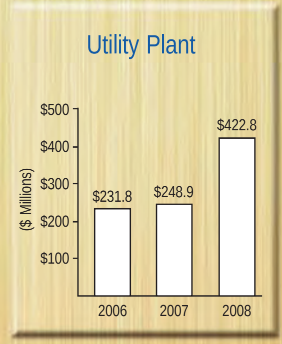
We initiated an internal self-assessment of our response to the storm and will participate in regulatory reviews of utility responses, with the goal of improving our own emergency preparedness and response effectiveness.

We honor our employees and the utility lineworkers who performed so tirelessly in restoring power to our customers by including their photos in the image on the front cover of this Annual Report.

The Economy

The national and global economies face the most challenging environment we have seen in generations. The bursting of the credit bubble – which reversed a decade of people living beyond their means on borrowed money – has led to a severe contraction in the





demand for goods and services.

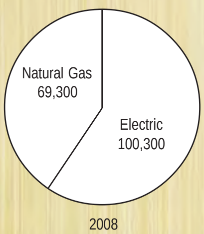
Economists do not agree on what comes next. The optimists see a recovery beginning in the second half of 2009. The pessimists see a prolonged economic slump, some even comparing it to Japan's lost decade in the 1990s. Governments worldwide are attempting to stimulate their economies with massive stimulus packages and a partial or complete nationalization of their banking systems. These are clearly unprecedented times.

In this environment, your Company is planning for an economic downturn lasting through 2010. We are budgeting operating and capital expenses accordingly. The previously discussed acquisition synergies will be an immense help towards managing our spending.

We have seen decreases in electric consumption in each of the last three years, due to high energy prices and the resulting conservation efforts of consumers. Offsetting this trend is an increase in the use of natural gas for heating and other purposes. We plan to pursue the expansion of natural gas usage in our territories, an initiative which is actively supported by current public policy and is being welcomed by our communities.

The major risk of a prolonged economic downturn is in the commercial and industrial sectors. Thus far we have seen these sectors holding their own.

Customers by Type



Access to Capital

One of the major business challenges today is access to credit. The good news is that your Company has demonstrated an ability to access short-term and long-term capital to meet its requirements. As a general rule, regulated utilities are seen as good credit and low-risk borrowers. Our proven access to capital markets, combined with our strong operating cash flow, provide us with the liquidity necessary to run the business. We constantly monitor the credit markets, as well as manage the use of cash to ensure continuing access to capital in these difficult times.

Debt and equity capital markets have largely been closed to many businesses. In 2008, we successfully raised $90 million in private placement debt at competitive fixed interest rates and raised $45 million in new equity to finance the acquisition of Northern Utilities and Granite State Gas Transmission.

We were particularly pleased with the issuance of 2.3 million new shares last December, as we were one of only a few companies able to access the equity markets in the last quarter of 2008. We anticipate completing a follow-on equity offering to finish the acquisition financing in 2009. We believe the results we reported for 2008 highlight the anticipated benefits of our acquisition.

The Way Forward

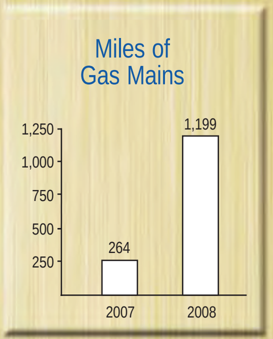
The Chinese word for crisis, wei-ji (危机), is composed of the two characters meaning danger and opportunity. It is an apt word to describe the environment we operate in today. As we have done in the past, we will weather the current economic downturn by concentrating on the following strategies:

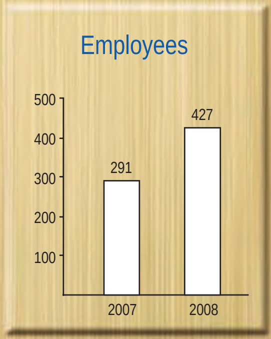
1. Seek to expand the use of natural gas in each of our franchise territories. The penetration rate in the New England region is only about 35%, thereby giving us the opportunity to increase gas sales. The demand for conversion to natural gas in each of our territories has been strong, particularly in the Northern Utilities service territory.

2. Implement a regulatory strategy to move towards a revenue decoupling model which will separate our revenues from gas and electric sales. This would eliminate the disincentive for our companies to promote conservation and energy efficiency actively without having to sacrifice our financial stability. In a nut shell, revenue decoupling works by adjusting the actual sales volumes to the weather-normalized sales volumes approved during the last rate case. When sales volumes deviate from the level forecasted in the rate case, the true-up mechanism makes a modest adjustment to the distribution charge, which gives the utility an opportunity to recover its authorized fixed costs, regardless of fluctuations in energy use. The transition towards this new revenue model will start in Massachusetts in 2009. We hope to make similar transitions in New Hampshire and Maine over the next few years. This will allow us to continue to have diversified and more stable revenue growth in the years ahead and to take a lead in the promotion of conservation efforts and the efficient use of energy by our customers.

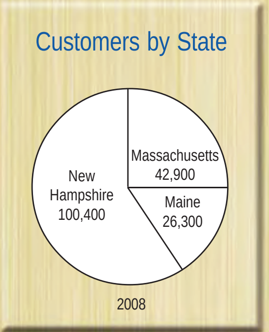
3. Continue the evolution toward a 21st century distribution utility model, gradually incorporating distributed and smart grid technologies. We now have the opportunity to make utility investments in certain types of alternative and distributed technologies in Massachusetts and New Hampshire. While this will be a gradual evolution, we believe it is the future for local distribution utility companies.

4. Redouble our commitment to be a customer-focused organization. The reaction of some of our customers to our response in last December's ice storm shows we have work to do. While our employees performed heroically, we need to improve our emergency pre-



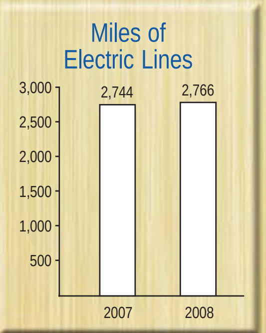


paredness and response efforts, including how we communicate with our customers. We have already begun this effort, and we will be a stronger Company as a result.



Conclusion

2008 was a transformative year for your Company. We achieved a long-desired strategic objective of growing through acquisitions, significantly increasing our utility assets and customer base. The acquisition of Northern Utilities and Granite State Gas Transmission will help diversify our revenue and earnings and will provide significant benefits to our customers, shareholders, and employees. The acquisition puts us in a good position to expand on this proven platform.



But challenges abound. Uncertain economic prospects require us to plan for a prolonged economic slowdown. We are prepared to do what is necessary to achieve our goal of increasing earnings per share 3% to 5% per year, even in these uncertain times.

For their extraordinary efforts throughout 2008, I want to thank all of our employees. They are among the best in our industry. That we are attracting first-class talent to help grow your Company underscores the fact that the Company is seen as an excellent place to work. We are all committed to being a customer-focused organization.

I also want to thank you, our shareholders, for your continued investment in, and support of, Unitil management and its employees.

Robert Schoenberger

Robert G. Schoenberger
Chairman of the Board of Directors
President & Chief Executive Officer

March 4, 2009

This Annual Report contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity, and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire (State or other jurisdiction of incorporation or organization)	**02-0381573** (I.R.S. Employer Identification No.)
6 Liberty Lane West, Hampton, New Hampshire (Address of principal executive offices)	**03842-1720** (Zip Code)

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Based on the closing price of June 30, 2008, the aggregate market value of common stock held by non-affiliates of the registrant was $148,801,666.

The number of common shares outstanding of the registrant was 8,095,724 as of February 17, 2009.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 16, 2009 are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2008
Table of Contents

[THIS PAGE INTENTIONALLY LEFT BLANK]

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly owned subsidiaries of Unitil:

Company Name	State and Year of Organization	Principal Business
Unitil Energy Systems, Inc. (Unitil Energy)	NH - 1901	Electric Distribution Utility
Fitchburg Gas and Electric Light Company (Fitchburg)	MA - 1852	Electric & Gas Distribution Utility
Northern Utilities, Inc. (Northern Utilities)	NH - 1979	Natural Gas Distribution Utility
Granite State Gas Transmission, Inc. (Granite State)	NH - 1955	Natural Gas Transmission Pipeline
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-regulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering and Advisory Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, originally founded as Portland Gas Light Company in 1849, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate natural gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the Acquisitions). Bay State is a wholly owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt (see "Liquidity, Commitments and Capital Requirements" section in Part II, Item 7 below).

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly owned distribution utilities: i) Unitil Energy, which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the city of Concord, New Hampshire, ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts, and iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area. In addition, Unitil is the parent company of Granite State, an interstate natural gas transmission pipeline company that principally provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory. Together, Unitil's three distribution utilities serve approximately 100,300 electric customers and 69,300 natural gas customers.

Unitil's distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in net utility plant of $422.8 million at December 31, 2008. Unitil's total revenue was $288.2 million in 2008. Earnings applicable to common shareholders for 2008 was $9.6 million. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are indirect subsidiaries that are wholly owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

OPERATIONS

Electric Distribution Utility Operations

Unitil's electric utility operations are conducted through two of the Company's distribution utilities, Unitil Energy and Fitchburg. Revenue from Unitil's electric utility operations was $227.5 million for 2008. Earnings from electric utility operations were $5.2 million for the same 12-month period.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its service territory in New Hampshire and Massachusetts. As a result of the implementation of choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The distribution utilities continue to deliver that supply of electricity over their distribution systems. Both Unitil Energy and Fitchburg supply electricity to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the distribution utilities being recovered on a pass-through basis under periodically-adjusted rates.

Unitil Energy distributes electricity to approximately 72,500 customers in New Hampshire in the capital city of Concord as well as parts of 12 surrounding towns and all or part of 18 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. Unitil Energy's service territory consists of approximately 408 square miles. In addition, Unitil Energy's service territory encompasses retail trading and recreation centers for the central and southeastern parts and includes the Hampton Beach recreational area. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics, healthcare and education. Unitil Energy's 2008 electric operating revenue was $161.0 million, of which approximately 49.0% was derived from residential sales and 51.0% from commercial/industrial sales.

Fitchburg is engaged in the distribution of both electricity and natural gas in the city of Fitchburg and several surrounding communities. Fitchburg's service territory encompasses approximately 170 square miles. Electricity is supplied and distributed by Fitchburg to approximately 27,800 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries and education. Fitchburg's 2008 electric operating revenue was $66.5 million, of which approximately 54.0% was derived from residential sales and 46.0% from commercial/industrial sales.

Gas Operations

Unitil's Gas Operations include gas distribution utility operations and gas transportation pipeline company operations, discussed below. Revenue from Unitil's gas operations was $56.9 million for 2008. Earnings from gas operations were $4.3 million for the same 12-month period. In 2008, the Company significantly expanded its gas operations by acquiring Northern Utilities and Granite State on December 1, 2008.

Gas Distribution Utility Operations

Unitil's natural gas utility operations are conducted through two of the Company's distribution utilities, Northern Utilities and Fitchburg. The primary business of Unitil's natural gas distribution utility operations is the local distribution of natural gas to customers in its service territory in New Hampshire, Massachusetts and Maine. As a result of a restructuring of the gas utility industry in New Hampshire, Massachusetts and Maine, Fitchburg's residential and commercial and industrial (C&I) customers and Northern Utilities' C&I customers have the opportunity to purchase their natural gas supplies from third party vendors. Most customers, however, continue to purchase such supplies through Northern Utilities and Fitchburg as the provider of last resort. Northern Utilities and Fitchburg purchase natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis through reconciling rate mechanisms that are periodically adjusted.

Natural gas is supplied and distributed by Northern Utilities to approximately 54,200 customers in 44 New Hampshire and southern Maine communities, from Plaistow, New Hampshire in the south to the city of Portland, Maine and then extending to Lewiston-Auburn, Maine in the north. Northern Utilities has a diversified customer base both in Maine and New Hampshire. Commercial businesses include healthcare, education, government and retail. Northern Utilities' industrial base includes manufacturers in the industries of auto, housing, rubber, printing, textile, pharmaceutical, electronics, wires and food production as well as a military installation. Northern Utilities 2008 gas operating revenue was $19.5 million, of which approximately 35.0% was derived from residential firm sales and 65.0% from commercial/industrial firm sales.

Natural gas is supplied and distributed by Fitchburg to approximately 15,100 customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. Fitchburg's 2008 gas operating revenue was $37.0 million, of which approximately 54.0% was derived from residential firm sales and 46.0% from commercial/industrial firm sales.

Gas Transmission Pipeline Company Operations

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State had operating revenue of $0.4 million for 2008. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Seasonality

Natural gas sales in New England are seasonal, and our results of operations reflect this seasonal nature. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by Northern Utilities, which was acquired by the Company on December 1, 2008. Accordingly, the Company expects that as a result of the Acquisitions consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours. Unitil Energy, Fitchburg and Northern Utilities are not dependent on a single customer or a few customers for their electric and natural gas sales.

Non-regulated and Other Non-Utility Operations

Unitil's non-regulated operations are conducted through Usource, a subsidiary of Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's non-regulated operations was $3.8 million in 2008. Earnings from Unitil's non-regulated operations were $0.3 million in 2008.

The results of Unitil's other non-utility subsidiaries, Unitil Service and Unitil Realty, and the holding company are included in the Company's consolidated results of operations. The results of these non-utility operations are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and are reported in Other segment income (for segment information, see Part II, Item 8, Note 11 herein). Unitil's other non-utility operations recognized a net loss of ($0.2) million in 2008.

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 with regard to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, with regard to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and Maine Public Utilities Commission (MPUC). Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party vendors. Most customers, however, continue to purchase such supplies through the distribution utilities. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features.

Also see Management's Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters and Note 7 to the accompanying Consolidated Financial Statements for additional information on Regulatory Matters.

ELECTRIC POWER SUPPLY

The transition to retail choice required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive suppliers. Retail choice has been successful for Unitil's largest customers. As of December 2008, 82 or 55% of Unitil's largest New Hampshire customers representing 18% of total New Hampshire electric sales and 27 or 84% of Unitil's largest Massachusetts customers representing 35%

of total Massachusetts electric sales are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities. The concentration of the competitive market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential and small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace.

Electric Power Supply Divestiture

Prior to May 1, 2003, Unitil Energy purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, Unitil Energy and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to Unitil Energy ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, Unitil Energy continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. In connection with the implementation of retail choice, Unitil Power and Fitchburg divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts.

Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets.

Unitil's distribution utilities have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Also see Management's Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Electric Power Supply.

NATURAL GAS SUPPLY

With the purchase of Northern Utilities on December 1, 2008, Unitil now manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and C&I customers have the opportunity to purchase their natural gas supply from third-party vendors, although most of Fitchburg's customers continue to purchase such supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply at regulated rates from Northern Utilities as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its city gate station or underground storage through its own long-term contracts with Tennessee Gas Pipeline. Fitchburg's gas supply is delivered to the city gate station or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), by truck to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern Utilities purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern Utilities arranges for gas delivery to its city gate station or underground storage through its own long-term contracts with various interstate pipeline and storage facilities, or through peaking supply contracts delivered to its city gate station. Northern Utilities gas supply is delivered to its city gate stations or in the case of LNG or LPG, by truck to each storage facility within Northern Utilities' service territory.

Northern Utilities has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Also see Management's Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Natural Gas Supply.

ENVIRONMENTAL MATTERS

Unitil's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2008, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed. Also, see Note 7 for additional discussion of Fitchburg's regulatory and environmental matters.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800s through the mid 1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Also, see Discussion and Analysis of Financial Condition and Results of Operations—Environmental Matters and Note 7 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES

As of December 31, 2008, the Company and its subsidiaries had 406 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2008, 144 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two of these agreements expire on March 31, 2009, two agreements expire on May 31, 2010, and one agreement expires on June 5, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is www.unitil.com. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the New York Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 18, 2009:

Name	Age	Position
Robert G. Schoenberger	58	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	49	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	46	Senior Vice President and Chief Operating Officer
Laurence M. Brock	55	Controller and Chief Accounting Officer
Todd R. Black	44	President, Usource
George R. Gantz	57	Senior Vice President, Customer Services and Communications, Unitil Service
George E. Long, Jr.	52	Vice President, Administration, Unitil Service
Raymond J. Morrissey	61	Vice President, Information Systems, Unitil Service
Sandra L. Whitney	45	Corporate Secretary
Dr. Robert V. Antonucci	63	Director
David P. Brownell	65	Director
Michael J. Dalton	68	Director
Albert H. Elfner, III	64	Director
Edward F. Godfrey	59	Director
Michael B. Green	59	Director
Eben S. Moulton	62	Director
M. Brian O'Shaughnessy	65	Director
Charles H. Tenney, III	61	Director
Dr. Sarah P. Voll	66	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board of Directors and Chief Executive Officer since 1997, as well as President since 2003. Prior to his employment with Unitil, Mr. Schoenberger was president and chief operating officer of the New York Power Authority (a state-owned utility operating 6,000 MW of generation and 1,400 miles of high voltage transmission) from 1993 until 1997. Mr. Schoenberger also serves as chairman and trustee of Exeter Health Resources, Exeter, New Hampshire, since 1998, and as a director of SatCon Technology Corporation, Boston, Massachusetts (a company engaged in the development and manufacture of power electronics and control systems) since 2007. Mr. Schoenberger was director of the Greater Seacoast (New Hampshire) United Way from 1998 until 2004, the New England Gas Association from 1999 until 2002 and the Southwest Power Pool from 2003 until 2005.

Mark H. Collin has been Unitil's Senior Vice President and Chief Financial Officer since February 2003. Mr. Collin has also served as Treasurer since 1998. Mr. Collin joined Unitil in 1988, and served as Vice President of Finance from 1995 until 2003.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President and Chief Operating Officer since June 2005. Mr. Meissner served as Senior Vice President, Operations, from February 2003 until June 2005. Mr. Meissner joined Unitil in 1994 and served as Director of Engineering from 1998 until 2003.

George R. Gantz has been Unitil's Senior Vice President, Customer Services and Communications, Unitil Service, since January 2003. Mr. Gantz joined Unitil in 1983 and served as Senior Vice President, Communication and Regulation, from 1994 until 2003.

Todd R. Black has been President of Usource since June 2003. Mr. Black joined Unitil in 1998 and served as Vice President, Sales and Marketing, for Usource from 1998 until 2003.

Laurence M. Brock has been Unitil's Controller and Chief Accounting Officer since June 2005. Mr. Brock joined Unitil in 1995 as Vice President and Controller, and is a certified public accountant in the state of New Hampshire.

George E. Long, Jr. has been Unitil's Vice President, Administration, Unitil Service, since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources, from 1998 until 2003.

Raymond J. Morrissey has been Unitil's Vice President, Information Systems, Unitil Service, since February 2003. Mr. Morrissey served as Unitil's Vice President of Customer Service from 1992 until 2003, and general manager of Fitchburg from 1991 until 1992. Mr. Morrissey joined Unitil in 1985.

Sandra L. Whitney has been Unitil's Corporate Secretary and secretary of our Board of Directors since February 2003. Ms. Whitney joined Unitil in 1990 and also serves as the Corporate Secretary of Unitil's subsidiary companies.

Dr. Robert V. Antonucci has been a member of Unitil's Board of Directors since 2004. Dr. Antonucci has been the president of Fitchburg State College (FSC) in Fitchburg, Massachusetts, since 2003. Prior to his employment with FSC, Dr. Antonucci was president of the School Group of Riverdeep, Inc., San Francisco, California, from 2001 until 2003 and president and chief executive officer of Harcourt Learning Direct and Harcourt Online College, Chestnut Hill, Massachusetts from 1998 until 2001. Dr. Antonucci also served as the commissioner of education for the Commonwealth of Massachusetts from 1992 until 1998. Dr. Antonucci also serves as a trustee of Eastern Bank (formerly Plymouth (Massachusetts) Savings Bank) since 1988.

David P. Brownell has been a member of Unitil's Board of Directors since 2001. Mr. Brownell has been a retired senior vice president of Tyco International Ltd. (Tyco) (a diversified global manufacturing and service company), Portsmouth, New Hampshire, since 2003. Mr. Brownell had been with Tyco since 1984. Mr. Brownell was also interim president of the University of New Hampshire Foundation (UNHF), former vice chairman of the board of UNHF, former volunteer board president of the United Way of the Greater Seacoast, and a former board member of the New Hampshire Junior Achievement Advisory Council.

Michael J. Dalton has been a member of Unitil's Board of Directors since 1984. Mr. Dalton has been the retired president and chief operating officer of Unitil since 2003. Mr. Dalton has been a member of the Industrial Advisory Board of the University of New Hampshire College of Engineering and Physical Sciences since 2003. Mr. Dalton was a director of the New England Gas Association from 2002 until 2003, the Electric Council of New England, the UNHF, the University of New Hampshire Alumni Association, and the University of New Hampshire President's Council.

Albert H. Elfner, III has been a member of Unitil's Board of Directors since 1999. Mr. Elfner was the chairman of Evergreen Investment Management Company, Boston, Massachusetts, from 1994 until 1999 and its chief executive officer from 1995 until 1999. Mr. Elfner is also a director of NGM Insurance Company (NGM), Jacksonville, Florida, as well as a member of the NGM finance committee.

Edward F. Godfrey has been a member of Unitil's Board of Directors since 2002. Mr. Godfrey was the executive vice president and chief operating officer of Keystone Investments, Incorporated (Keystone), Boston, Massachusetts, from 1997 until 1998. Mr. Godfrey was senior vice president, chief financial officer and treasurer of Keystone from 1988 until 1996. Mr. Godfrey is also a director of VehiCare, LLC, Charlotte, North Carolina, since 2006.

Michael B. Green has been a member of Unitil's Board of Directors since 2001. Mr. Green has been the president and chief executive officer of Capital Region Health Care and Concord Hospital, Concord, New Hampshire, since 1992. Mr. Green is also a member of the adjunct faculty, Dartmouth Medical School, Dartmouth College, Hanover, New Hampshire. In addition, Mr. Green currently serves on the board of the Foundation for Healthy Communities, is a director of the New Hampshire Hospital Association, a director of New Hampshire Business Committee for the Arts, and a director of Merrimack County Savings Bank including membership on the bank's investment and audit committees.

Eben S. Moulton has been a member of Unitil's Board of Directors since 2000. Mr. Moulton has been the managing partner of Seacoast Capital Corporation, Danvers, Massachusetts, (a private investment company) since 1995. Mr. Moulton is also a director of IEC Electronics (a complex circuit boards manufacturer), a director of six private companies, and a trustee of Colorado College, Colorado Springs, Colorado.

M. Brian O'Shaughnessy has been a member of Unitil's Board of Directors since 1998. Mr. O'Shaughnessy has been the chairman of the board of Revere Copper Products, Inc. (Revere), Rome, New York, since 1988. Mr. O'Shaughnessy also served as chief executive officer and president of Revere from 1988 until 2007. Mr. O'Shaughnessy also serves on the Board of Directors of the Coalition for a Prosperous America, three copper industry trade associations, three manufacturing associations in New York State regarding energy-related issues, and the Economic Development Growth Enterprise of Mohawk Valley.

Charles H. Tenney III has been a member of Unitil's Board of Directors since 1992. Mr. Tenney was the director of operations of BrainShift.com, Inc., Medford, Massachusetts (a learning technology development company) from 2002 until 2008. Mr. Tenney is currently a director of The BrainShift Foundation (a non-profit division of BrainShift.com, Inc. engaged in energy conservation). Mr. Tenney also served as a member of the board of overseers of the Huntington Theater Company, Boston, Massachusetts, from 2004 until 2006.

Dr. Sarah P. Voll has been a member of Unitil's Board of Directors since 2003. Dr. Voll has been a retired vice president, National Economic Research Associates, Inc. (NERA), Washington, District of Columbia, a firm of consulting economists specializing in industrial and financial economics, since 2007. Dr. Voll had been with NERA in the position of vice president since 1999, and in the position of senior consultant from 1996 until 1999. Prior to her employment with NERA, Dr. Voll was a staff member at the NHPUC from 1980 until 1996.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 16, 2009, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of common stock, administration of the Dividend Reinvestment and Stock Purchase Plan, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Computershare
P.O. Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

Investor Relations

For information about the Company, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at *www.unitil.com*; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available to Holders of Record

If a shareholder's shares of common stock are registered directly in the shareholder's name with the Company's transfer agent, the shareholder is considered a holder of record of the shares. The following services and programs are available to shareholders of record:

- Internet Account Access is available at *www.computershare.com*.
- Dividend Reinvestment and Stock Purchase Plan:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Direct Registration:

  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

Risks related to the regulation of the Company's business could impact the rates it is able to charge, its costs and its profitability.

The Company is subject to comprehensive regulation by federal and state regulatory authorities, which significantly influences the Company's operating environment and its ability to recover costs from its customers. In particular, the Company is regulated by the FERC and state regulatory authorities with jurisdiction over public utilities, including the NHPUC, MDPU and MPUC. These authorities regulate many aspects of the Company's operations, including, but not limited to, construction and maintenance of facilities, operations, safety, issuance of securities, accounting matters, transactions between affiliates, the rates that the Company can charge customers and the rate of return that it is allowed to realize. The Company's ability to obtain rate adjustments to maintain its current rate of return depends upon regulatory action under applicable statutes, rules and regulations, and the Company cannot assure you that it will be able to obtain rate adjustments or continue receiving its current authorized rates of return. These regulatory authorities are also empowered to impose financial penalties and other sanctions on the Company if it is found to have violated statutes and regulations governing its utility operations. The Company is unable to predict the impact on its operating results from the regulatory activities of any of these agencies. Although the Company has attempted to actively manage the rate making process and has had recent success in obtaining rate adjustments, it can offer no assurances as to future success in the rate making process. Despite the Company's requests, these regulatory commissions have authority under applicable statutes, rules and regulations to leave the Company's rates unchanged, grant increases or order decreases in such rates.

The regulators also have authority with respect to the recovery of the Company's electricity and natural gas supply costs incurred by Unitil Energy, Fitchburg, and Northern Utilities. In the event that the Company is unable to recover these costs or recovery of these costs were to be significantly delayed, the Company's operating results could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have an adverse effect on the Company's operating results.

As a result of electric industry restructuring, the Company has a significant amount of certain stranded electric generation and generation related supply costs.

The stranded costs resulting from the implementation of electric industry restructuring mandated by the states of New Hampshire and Massachusetts are recovered by the Company on a pass-through basis through periodically reconciled rates. Any unrecovered balance of purchased power or stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

The Company's power supply portfolio related stranded costs due to the electric industry restructuring in New Hampshire and Massachusetts for which regulatory approval has been obtained for recovery were approximately $33.8 million for Fitchburg and $18.9 million for Unitil Energy as of December 31, 2008, including $8.3 million and $9.8 million for Fitchburg and Unitil Energy, respectively, in Accrued Revenue on the Company's Consolidated Balance Sheet. Additionally, the Company's other restructuring-related regulatory assets for which regulatory approval has been obtained for recovery were approximately $29.1 million in the aggregate as of December 31, 2008, including $4.0 million in Accrued Revenue on the Company's Consolidated Balance Sheet.

Substantially all of Fitchburg's stranded costs relate to owned generation assets and purchase power agreements divested by Fitchburg under a long-term contract buy-out agreement. Unitil Energy's stranded costs are attributable to the long-term power purchase agreements divested by Unitil Power under long-term contract buyout agreements. Because Fitchburg and Unitil Power remain ultimately responsible for purchase power payments underlying these long-term buyout agreements, Fitchburg and Unitil Power could incur additional stranded costs were they required to resell such divested entitlements prior to the end of their term for amounts less than the amounts agreed to under the existing long-term buyout agreements. The Company expects that any such additional stranded costs would be recovered from its customers, although such recovery would require approval from the MDPU or NHPUC, the receipt of which cannot be assured.

The Company's electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may negatively impact the Company's customers and correspondingly its operating results and financial condition.

The Company's business is influenced by the economic activity of its service territory. The level of economic growth in the Company's electric and natural gas distribution service territory directly affects its potential for future growth in its business. As a result, adverse changes in the economy, including the significant adverse changes in the economy in 2008, may have negative effects on the Company's revenues, operating results and financial condition.

The Company may not be able to obtain debt financing, obtain debt financing on acceptable terms, or obtain debt financing under its current credit facilities because of the deterioration of the credit and capital markets, which could have an adverse affect on the Company's operating results and financial condition.

The Company requires capital to fund utility plant additions, working capital and other utility expenditures. While the capital necessary to meet these requirements is derived primarily from internally-generated funds, the Company initially supplements internally generated funds through short-term debt financings, as needed, and periodically replaces portions of its short-term debt with long-term debt. General economic conditions, including recent distress in the financial markets, have had an adverse impact on the availability of credit resources generally, which could negatively affect the Company's ability to obtain short- and long-term debt financings and the terms of such financings. In addition, the Company may be unable to obtain debt financing under its current credit facilities because its lending counterparties may be unwilling or unable to meet their funding obligations. In each case, this could hinder or prevent the Company from meeting its future capital needs, which could correspondingly have an adverse affect on the Company's operating results and financial condition. In addition, the material terms of the Company's existing indebtedness will also restrict its ability to incur any material amount of additional indebtedness, which could negatively impact its operating results and financial condition. See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements and Note 5 to the accompanying Consolidated Financial Statements.

Declines in the valuation of capital markets could require the Company to make substantial cash contributions to cover its pension obligations, which could negatively impact its financial condition.

On August 17, 2006, the Pension Protection Act of 2006 (the PPA) was signed into law. Included in the PPA are new minimum funding rules which came into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period provided pursuant to the PPA. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 – 2010 plan years.

The Company made cash contributions of $2.8 million, $2.8 million and $2.5 million to its pension plan in 2008, 2007 and 2006, respectively, which exceeded minimum funding requirements. Recent and future declines in the valuation of capital markets could require the Company to make cash contributions to its pension plans substantially in excess of its cash contributions in prior years, which could adversely affect its financial condition.

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires companies to record on their balance sheets the funded status of their retirement benefit obligations (RBO). The Company has recognized a liability for the projected RBO of its plans and a corresponding regulatory asset, to recognize the future collection of these obligations in electric and gas rates. In the event that the Company is unable to recover these costs or recovery of these costs were to be significantly delayed, the Company's operating results could be materially adversely affected. See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements and Note 10 to the accompanying Consolidated Financial Statements.

Increases in interest rates could have a negative impact on the Company's financial condition and the Company may need to use a significant portion of its cash flow to repay its outstanding indebtedness.

The Company and its utility subsidiaries have ongoing capital expenditure and cash funding requirements that they frequently fund by issuing short-term debt and long-term debt.

Short-term debt borrowings are typically at variable rates of interest. Therefore, changes in short-term interest rates will increase or decrease the Company's interest expense associated with short-term borrowings. Increases in interest rates generally will increase the Company's borrowing costs with respect to short-term debt and could adversely affect its financial condition or results of operations. As of December 31, 2008, the Company had approximately $39.1 million outstanding under a bank financing facility, which provides for a loan which matures on November 1, 2009, and $35.0 million outstanding under a revolving credit facility.

Long-term debt borrowings are typically at fixed rates of interest. Therefore, changes in interest rates do not affect interest expense associated with presently outstanding fixed rate long-term debt securities. However, changes in interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities that are issued. See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements and Note 5 to the accompanying Consolidated Financial Statements.

The Company may need to use a significant portion of its cash flow to repay its short-term debt and long-term debt, which would limit the amount of cash it has available for working capital, capital expenditures and other general corporate purposes and could negatively affect its liquidity, financial condition and results of operations.

The Company's and its subsidiaries' indebtedness contains covenants that could restrict the Company's business operations.

See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements and Note 5 to the accompanying Consolidated Financial Statements.

Weather conditions may cause the Company's sales to vary from year to year.

Sales by the Company's distribution utilities vary from year to year, depending on weather conditions. The Company estimates that approximately 50% of its annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of natural gas sold by the Company in any year, particularly during the winter heating season. The Company's electric sales are generally less sensitive to weather than its natural gas sales, but may also be affected by weather conditions in both the winter and summer seasons. The highest usage of electricity typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours.

The Company's results of operations reflect this seasonal nature. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by Northern Utilities, which was acquired by the Company on December 1, 2008. Accordingly, the Company expects that consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Unitil is a holding company and has no operating income of its own. The Company's ability to pay dividends on its common stock is dependent on dividends received from its subsidiaries and on factors directly affecting Unitil, the parent corporation. The Company cannot assure you that its current annual dividend will be paid in the future.

Unitil is a public utility holding company and it does not have any operating income of its own. Consequently, the Company's ability to pay dividends on its common stock is dependent on dividends and other payments received from its subsidiaries, principally Unitil Energy, Fitchburg, Northern Utilities and Granite State. The ability of the Company's subsidiaries to pay dividends or make distributions to Unitil will depend on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of our subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by the Company's subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of Unitil Energy, Fitchburg, Northern Utilities and Granite State and that may be contained in future debt agreements of the Company's subsidiaries, if any; and
- limitations that may be imposed by New Hampshire, Massachusetts and Maine state regulatory agencies.

In addition, the Company may incur indebtedness in the future. Before the Company can pay dividends on its common stock, it has to satisfy its debt obligations, including the bank financing facility that the Company used to partially finance the Acquisitions and the long-term notes issued by Northern Utilities and Granite State, and comply with any statutory or contractual limitations.

The Company's current annual dividend is $1.38 per share of common stock, payable quarterly. However, the Company's Board of Directors reviews Unitil's dividend policy periodically in light of the factors referred to above, and the Company cannot assure the amount of dividends, if any, that may be paid in the future.

Transporting and storing natural gas and supplemental gas supplies, as well as electricity, involves numerous risks that may result in accidents and other operating risks and costs.

Inherent in the Company's electric and natural gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions, electrocutions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, and impairment of the Company's operations and substantial losses to Unitil. In accordance with customary industry practice, the Company maintains insurance against some, but not all, of these risks and losses. The location of pipelines, storage facilities and electric distribution equipment near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect the Company's financial position and results of operations.

The Company's business is subject to environmental regulation in all jurisdictions in which it operates and its costs of compliance are significant. Any changes in existing environmental regulation and the incurrence of environmental liabilities could negatively affect the Company's results of operations and financial condition.

The Company's utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources, and the health and safety of the Company's employees. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; imposition of remedial requirements; and even issuance of injunctions to ensure future compliance. Liability under certain environmental laws is strict, joint and several in nature. Although the Company believes it is in general compliance with all applicable environmental and safety laws and regulations, there can be no assurance that significant costs and liabilities will not be incurred in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, could result in increased environmental compliance costs.

Catastrophic events could have a material adverse effect on the Company's financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could have a material adverse effect on the Company since they could inhibit its ability to continue providing electric and/or natural gas distribution services to its customers for an extended period, which is the principal source of the Company's operating income.

The Company's business could be adversely affected if it is unable to retain its existing customers or attract new customers.

The success of the Company's business depends, in part, on its ability to maintain and increase its customer base. The Company's failure to maintain or attract customers could have a material adverse effect on its business, financial condition and operating results.

The Company cannot guarantee customers' future performance under multi-year energy brokering contracts.

The Company's non-regulated energy brokering business provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenues from this business are primarily derived from brokering fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts. The Company cannot guarantee customers' future performance under multi-year energy brokering contracts.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2008, Unitil owned, through its distribution utilities, three utility operation centers, approximately 2,173 pole miles of local transmission and distribution overhead electric lines and 593 conduit bank miles of underground electric distribution lines, along with 49 electric substations, including three mobile electric substations. Our natural gas operations property includes two liquid propane gas plants, two liquid natural gas plants and 1,199 miles of underground gas mains. In addition, our real estate subsidiary, Unitil Realty, owns our corporate headquarters building and the 12 acres of land on which it is located.

Unitil Energy owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. Unitil Energy's 30 electric distribution substations, including a 5,000 kilovolt ampere (kVA) mobile substation, constitute 214,037 kVA of capacity, which excludes capacity of spare transformers, for the transformation of electric power from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by Unitil Energy or land occupied by Unitil Energy pursuant to perpetual easements.

Unitil Energy has a total of approximately 1,613 pole miles of local transmission and distribution overhead electric lines and a total of 413 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Unitil Energy without objection by the owners. In the case of certain distribution lines, Unitil Energy owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

The physical utility properties of Unitil Energy, with certain exceptions, and its franchises are subject to its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of Unitil Energy are outstanding.

Fitchburg's electric properties consist principally of 560 pole miles of local transmission and distribution overhead electric lines, 180 conduit bank miles of underground electric distribution lines and 19 transmission and distribution stations (including two mobile electric substations). The capacity of these substations totals 443,150 kVA, which excludes capacity of spare transformers.

Fitchburg owns a liquid propane gas plant and a liquid natural gas plant, both of which are located on land owned by Fitchburg. Fitchburg also has 264 miles of underground steel, cast iron and plastic gas mains.

Fitchburg's electric substations, with minor exceptions, are located on land owned by Fitchburg or occupied by Fitchburg pursuant to perpetual easements. Fitchburg's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Fitchburg without objection by the owners. Fitchburg leases its distribution operations center located in Fitchburg, Massachusetts.

Northern Utilities' distribution system is comprised of 935 miles of gas mains and 38,262 service pipes. The gas mains are primarily made up of polyethylene plastic (65%), coated and wrapped cathodically protected steel (22%), cast/wrought iron (8%), and unprotected bare and coated steel (5%).

Northern Utilities' New Hampshire division serving 21 communities has 470 miles of distribution gas mains and 19,288 service pipes. Northern Utilities' Maine division serving 23 communities has 465 miles of distribution and 18,974 service pipes. Northern Utilities also owns a liquid propane gas plant on land owned by Northern Utilities.

Granite State is a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline located in Maine and New Hampshire.

The Company believes that its facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. The complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg’s service territory in December, 2008. As of this date the complaint has not been served on Fitchburg. The Company believes this complaint is without merit, and will defend itself vigorously.

Item 4. Submission of Matters to a Vote of Security Holders

None

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's common stock is listed on the New York Stock Exchange under the symbol "UTL". As of December 31, 2008, there were 1,667 shareholders of record.

Common Stock Data

Dividends per Common Share	2008	2007
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2008		2007	
Price Range of Common Stock	High/Ask	Low/Bid	High/Ask	Low/Bid
1st Quarter	**$29.00**	**$25.75**	$27.30	$25.10
2nd Quarter	**$28.60**	**$26.41**	$28.40	$26.65
3rd Quarter	**$27.94**	**$25.46**	$31.73	$27.07
4th Quarter	**$26.60**	**$19.50**	$29.97	$25.75

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

EQUITY COMPENSATION PLAN BENEFIT INFORMATION

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
Restricted Stock Plan (1)	—	N/A	74,105
Equity compensation plans not approved by security holders			
1998 Option Plan (2)	97,200	$27.16	—
Total	97,200	$27.16	74,105

NOTES: (also see Note 4 to the accompanying Consolidated Financial Statements)

(1) The Restricted Stock Plan was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006; 9,020 shares of restricted stock were awarded to Plan participants in February 2007; 15,540 shares of restricted stock were awarded to Plan participants in February 2008; 32,260 shares of restricted stock were awarded to Plan participants in February 2009.

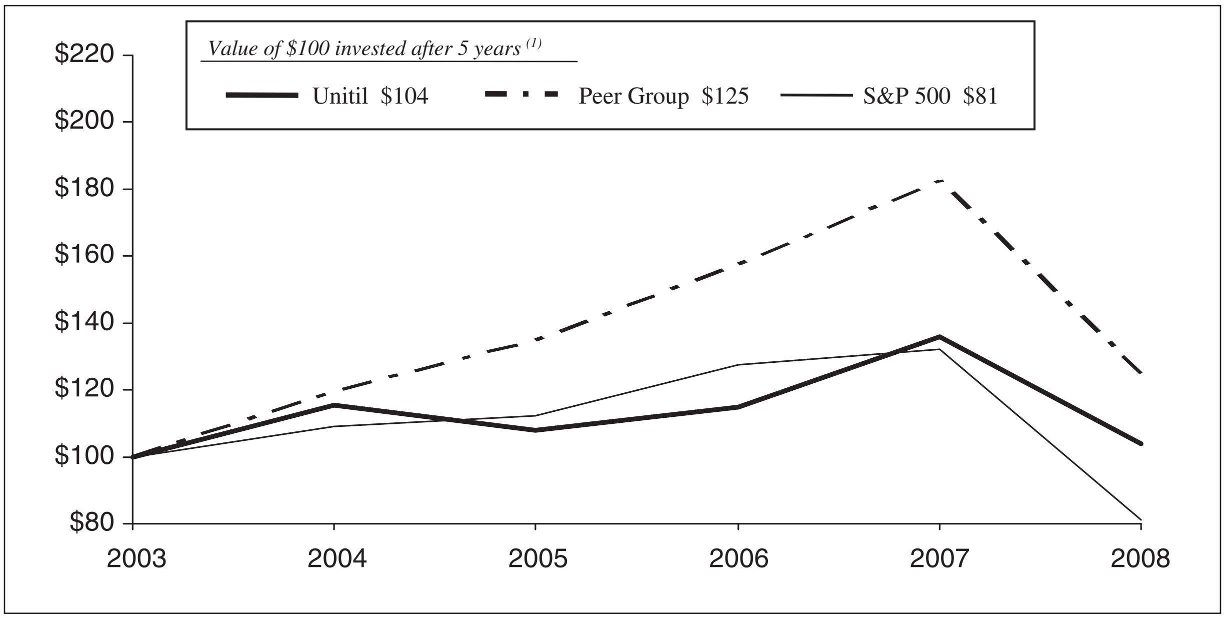
(2) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange (the exchange upon which the Company was then listed) rules, to obtain shareholder approval. Options

were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the 1998 Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the 1998 Option Plan were deregistered with the Securities and Exchange Commission. The 1998 Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the 1998 Option Plan. No further grants of options will be made thereunder.

Stock Performance Graph

The following graph compares Unitil Corporation's cumulative stockholder return since December 31, 2003 with the Peer Group index, comprised of the S&P Utility Index, and the S&P 500 index. The graph assumes that the value of the investment in the Company's common stock and each index (including reinvestment of dividends) was $100 on December 31, 2003.

Comparative Five-Year Total Returns



NOTES:

(1) The graph above assumes $100 invested on December 31, 2003, in each category and the reinvestment of all dividends during the five-year period. The Peer Group is comprised of the S&P Utility Index.

Unregistered Sales of Equity Securities and Uses of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2008.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 20, 2008, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases; however, the trading plan will terminate when $82,500 in value of shares have been purchased or on March 20, 2009. As of December 31, 2008, the approximate value of shares that may yet be purchased under the plans or programs was $4,000. Company repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
10/1/08 – 10/31/08	—	—	—
11/1/08 – 11/30/08	—	—	—
12/1/08 – 12/31/08	2,754	$22.33	2,754
Total	2,754	$22.33	2,754

Item 6. Selected Financial Data

For the Years Ended December 31,	2008	2007	2006	2005	2004
(all data in millions except shares, % and per share data) (1)					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 288.2**	$ 262.9	$ 260.9	$ 232.1	$ 214.1
Operating Income	**20.5**	18.5	15.8	15.5	15.2
Other Non-operating Expense (Income)	**0.3**	0.2	—	0.1	0.2
Income Before Interest Expense, net	**20.2**	18.3	15.8	15.4	15.0
Interest Expense, net	**10.5**	9.6	7.8	6.8	6.8
Net Income	**9.7**	8.7	8.0	8.6	8.2
Dividends on Preferred Stock	**0.1**	0.1	0.1	0.2	0.2
Earnings Applicable to Common Shareholders	**$ 9.6**	$ 8.6	$ 7.9	$ 8.4	$ 8.0
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 641.4**	$ 380.5	$ 353.0	$ 325.0	$ 308.1
Total Assets	**$ 735.2**	$ 474.6	$ 483.4	$ 450.1	$ 457.0
Capitalization:					
Common Stock Equity	**$ 139.5**	$ 100.4	$ 97.8	$ 96.3	$ 94.3
Preferred Stock	**2.0**	2.1	2.1	2.3	2.3
Long-Term Debt, less current portion	**249.3**	159.6	140.0	125.4	110.7
Total Capitalization	**$ 390.8**	$ 262.1	$ 239.9	$ 224.0	$ 207.3
Current Portion of Long-Term Debt	**$ 0.4**	$ 0.4	$ 0.3	$ 0.3	$ 0.3
Short-term Debt	**$ 74.1**	$ 18.8	$ 26.0	$ 18.7	$ 25.7
Capital Structure Ratios:					
Common Stock Equity	**36%**	38%	41%	43%	46%
Preferred Stock	**1%**	1%	1%	1%	1%
Long-Term Debt	**63%**	61%	58%	56%	53%
Earnings Per Share Data:					
Earnings Per Average Share	**$ 1.65**	$ 1.52	$ 1.41	$ 1.51	$ 1.45
Common Stock Data:					
Shares of Common Stock – (Average Outstanding, 000's)	**5,830**	5,672	5,612	5,568	5,525
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.90**	$ 17.50	$ 17.30	$ 17.21	$ 17.00
Electric and Gas Sales:					
Electric Distribution Sales (Millions kWh)	**1,695.9**	1,743.0	1,751.5	1,790.4	1,742.1
Firm Natural Gas Distribution Sales (Millions Therms)	**47.2**	28.4	26.4	24.3	23.2

(1) As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

OVERVIEW

Unitil is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy, which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,300 electric customers and 69,300 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite State, a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in Net Utility Plant of $422.8 million at December 31, 2008. Unitil's total revenue was $288.2 million in 2008, which includes revenue to recover the cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not affected by changes in the cost of purchased electricity and natural gas. Earnings applicable to common shareholders for 2008 were $9.6 million. Substantially all of Unitil's earnings are derived from the return on investment in the three distribution utilities and Granite.

Unitil also conducts non-regulated operations principally through Usource, which is wholly-owned by Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Usource's total revenues were $3.8 million in 2008. The Company's other subsidiaries include Unitil Service, which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, and Unitil Realty, which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- The Company's ability to complete the integration of the business, operations and personnel of Northern Utilities and Granite State and to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions, including recent distress in the financial markets that has had an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of our counterparty obligations, including those of our insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A Risk Factors.

RESULTS OF OPERATIONS

The following discussion of the Company's financial condition and results of operations should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report.

Net Income and EPS Overview

2008 Compared to 2007—The Company's Earnings Applicable to Common Shareholders was $9.6 million for 2008, an increase of 12% over 2007 Earnings of $8.6 million. Earnings per common share were $1.65 for 2008, $0.13 per share higher than last year.

Earnings in 2008 reflect the acquisitions, on December 1, 2008, of Northern Utilities and Granite State, which drove higher gas sales margins.

The following table presents the significant items (discussed below) contributing to the change in earnings per share in 2008 as compared to 2007:

2008 Earnings Per Share vs. 2007

	2007	**$1.52**
Electric Sales Margin		(0.15)
Gas Sales Margin		0.72
Usource Sales Margin		0.01
Operation and Maintenance Expense		(0.14)
Depreciation, Amortization and Other		(0.22)
Interest Expense, Net		(0.09)
	2008	**$ 1.65**

Electric sales margin decreased $1.4 million in 2008 compared to 2007. The decrease in electric sales margin primarily reflects lower sales volumes, partially offset by higher electric base rates implemented in March of 2008. Total electric kilowatt-hour (kWh) sales decreased 2.7% in 2008 compared to 2007 driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

Natural gas sales margin increased $6.7 million in 2008 compared to 2007. This increase reflects $5.4 million of gas sales margin from Northern Utilities and Granite State and an additional increase of $1.3 million in gas sales margin reflecting higher rates implemented in November 2007 and higher sales to Commercial and Industrial (C&I) customers. Overall, natural gas sales increased 66.2% in 2008 compared to 2007. Excluding the contribution of the acquisition of Northern Utilities, total therm sales of natural gas increased 1.1% in 2008 compared to 2007.

Total Operation & Maintenance (O&M) expenses increased $1.3 million, or 5.0%, in 2008 compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.9 million of the increase. In addition, the increase in O&M expenses reflects higher employee and retiree compensation and benefit expenses of $2.7 million, including increased employee benefits of $1.4 million, driven primarily by higher medical claims in 2008 and higher employee benefits related to staffing increases, and higher salaries and compensation of $1.3 million, due to normal annual increases and staffing additions. Also contributing to the increase in O&M expenses were higher utility operating costs of $0.3 million and higher bad debt expenses of $0.3 million, partially offset by a reduction of $2.8 million from the proceeds of an insurance settlement and lower professional fees of $0.1 million.

Depreciation, Amortization, Taxes and Other expenses increased $2.2 million in 2008 compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.9 million of the increase. In addition, the increase in Depreciation, Amortization, Taxes and Other expenses reflects the amortization, in the first quarter of 2008, of $0.7 million of natural gas inventory carrying costs deferred under a previous regulatory ruling, higher depreciation on normal utility plant additions and higher property and payroll taxes. Partially offsetting these increases were lower amortization costs of $0.8 million.

Interest Expense, Net increased $0.9 million in 2008 compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.3 million of the increase. The increase associated with the acquisitions is due to $0.5 million of interest expense from the issuance of long-term notes by Northern Utilities and Granite State in December 2008, partially offset by interest income on regulatory mechanisms. In addition to the increase related to the acquisitions, the remaining $0.6 million increase in Interest Expense, Net reflects higher debt outstanding and lower interest earned on regulatory assets compared to the prior period.

Usource, our non-regulated energy brokering business, recorded revenues of $3.8 million in 2008, an increase of $0.1 million over 2007. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

On December 11, 2008 a severe ice storm hit the Northeast creating massive extended power outages for many residents of Massachusetts and New Hampshire, including Unitil's electric customers in New Hampshire and the greater Fitchburg, Massachusetts service area. Based on its preliminary assessment, the Company has accrued and deferred approximately $10 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of storm restoration expenditures will be determined in future regulatory proceedings.

In 2008, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2009 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

2007 Compared to 2006—The Company's Earnings Applicable to Common Shareholders was $8.6 million for 2007, an increase of 9% over 2006 Earnings of $7.9 million. Earnings per common share were $1.52 for 2007, $0.11 per share higher than 2006. Earnings in 2007 reflect higher electric and gas sales margins, driven by higher rates and increased sales of natural gas, and improved profits from Usource, Unitil's non-regulated energy-brokering business. Partially offsetting these factors were higher operating expenses.

A more detailed discussion of the Company's 2008 and 2007 results of operations and a year-to-year comparison of changes in financial position are presented below.

Subsequent Event

On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. As part of this offering, the Company granted the underwriters a 30-day over-allotment option to purchase additional shares. The underwriters exercised the over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increases to Common Equity and Cash from the over-allotment sales were approximately $5.1 million (after payment of the underwriting discount and offering expenses) and were used to repay a portion of the short-term indebtedness used for the Company's acquisitions of Northern Utilities and Granite State. The Company recorded the issuance of the 270,000 shares, the sale proceeds and the increase in Common Equity in January 2009.

Balance Sheet

The Company's Balance Sheet as of December 31, 2008 reflects the acquisitions of Northern Utilities and Granite State, which closed on December 1, 2008. Certain prior period balances have been reclassified to conform to current year presentation. Most significant has been the reclassification of certain balance sheet amounts between Regulatory Assets and Accrued Revenue and between current and noncurrent Energy Supply Contract Obligations.

The Company's Total Assets increased by $260.6 million in 2008 compared to 2007. The increase in Total Assets was driven by: an increase of $173.9 million in the Company's investment in Net Utility Plant, due to the acquisitions of Northern Utilities and Granite State and to capital expenditures related to Unitil Energy's and Fitchburg's electric and gas distribution systems; increases in Cash, Accounts Receivable, Accrued Revenue, Gas Inventory and other current assets of $77.4 million, primarily due to the acquisitions of Northern Utilities and Granite State; an increase in Other Noncurrent Assets of $9.6 million in 2008 compared to 2007, due to deferred amortizable charges for transition and transaction costs of $7.6 million associated with the acquisitions of Northern Utilities and Granite State, partially offset by a decrease in all other assets of $0.3 million.

The Company's Total Capitalization increased by $128.7 million in 2008 compared to 2007. This increase reflects an increase of $39.1 million in Common Equity, primarily due to the issuance of common shares by the Company as part of its financing of the acquisitions of Northern Utilities and Granite State (See Note 4 to the accompanying Consolidated Financial Statements), and an increase in Long-Term Debt of $89.7 million reflecting the issuance and sale of $80 million of Senior Unsecured Notes by Northern Utilities on December 3, 2008 and the issuance and sale of $10 million of Senior Unsecured Notes by Granite State on December 15, 2008, both through private placements to institutional investors (See Note 5 to the accompanying Consolidated Financial Statements).

The Company's Total Liabilities increased $131.9 million in 2008 compared to 2007 reflecting an increase in Current Liabilities and Non-Current Liabilities of $124.5 million and $9.7 million respectively, partially offset by a decrease in Deferred Income Taxes of $2.3 million. The increase in Current Liabilities was driven by an increase in Accounts Payable of $18.7 million, primarily due to the acquisitions of Northern Utilities and Granite State; an increase of $55.3 million in Short-Term Debt, including the $39.1 million remaining on the bank financing facility which was used to finance a portion of the acquisitions of Northern Utilities and Granite State, and increased borrowings for utility operating purposes; an increase of $22.0 million in Energy Supply Contract Obligations, primarily related to natural gas payment obligations associated with Northern Utilities; and an increase in Other Current Liabilities of $28.5 million. The increase in Other Current Liabilities includes: accrued storm restoration costs of $9.5 million related to the December 2008 ice storm experienced in the Company's service territories, $7.7 million of payments due to NiSource, Inc. in connection with the Company's acquisitions of Northern Utilities and Granite State, and $4.5 million of recoverable, accrued gas supply costs and an increase of $6.8 million in all other items.

The increase in Noncurrent Liabilities was driven by: an increase of $19.2 million in Retirement Benefit Obligations reflecting $4.4 million of retirement plan obligations associated with the acquisitions of Northern Utilities and Granite State and a net increase of $14.8 million in the actuarial obligations of the Company's other pension and postretirement benefit obligations, primarily due to the poor performance of capital markets during 2008 which adversely affected the Company's pension plan assets (See Note 10 to the accompanying Consolidated Financial Statements); an increase of $8.3 million in Other Noncurrent Liabilities, reflecting $3.1 million of accrued regulatory compliance costs for Northern Utilities (See Note 7 to the accompanying Consolidated Financial Statements), $2.6 of accrued integration costs associated with the acquisitions of Northern Utilities and Granite State, $1.1 million of long-term recoverable accrued gas supply costs and an increase in all other items of $1.5 million; and an increase of $0.3 million in Environmental Obligations. These increases were partially offset by a decrease of $18.1 million in Energy Supply Contract Obligations, reflecting current year cost recoveries.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales—Unitil's total electric kWh sales decreased 2.7% in 2008 compared to 2007. Electric kWh sales to residential customers and C&I customers decreased 2.2% and 3.0%, respectively, in 2008 compared to 2007. The lower electric kWh sales in 2008 compared to 2007 were driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

Unitil's total electric kWh sales decreased 0.5% in 2007 compared to 2006. Electric kWh sales to residential customers increased 0.4% in 2007 compared to 2006. The lower total kWh sales in 2007 compared to 2006 were driven by milder summer temperatures in 2007 compared to 2006, energy conservation by customers in response to higher overall energy prices and a slowing economy.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (millions)

				2008 vs. 2007		2007 vs. 2006	
	2008	**2007**	**2006**	**Change kWh**	**Change %**	**Change kWh**	**Change %**
Residential	**660.2**	674.8	672.2	(14.6)	(2.2%)	2.6	0.4%
Commercial / Industrial	**1,035.7**	1,068.2	1,079.3	(32.5)	(3.0%)	(11.1)	(1.0%)
Total	**1,695.9**	1,743.0	1,751.5	(47.1)	(2.7%)	(8.5)	(0.5%)

Electric Operating Revenues and Sales Margin—The following table details Total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenues (millions)

				2008 vs. 2007		2007 vs. 2006	
	2008	**2007**	**2006**	**$ Change**	**% Change[1]**	**$ Change**	**% Change[1]**
Electric Operating Revenue:							
Residential	**$114.5**	$114.7	$105.9	$(0.2)	(0.1%)	$ 8.8	3.9%
Commercial / Industrial	**113.0**	110.3	119.3	2.7	1.2%	(9.0)	(4.0%)
Total Electric Operating Revenue	**$227.5**	$225.0	$225.2	$ 2.5	1.1%	$(0.2)	(0.1%)
Cost of Electric Sales:							
Purchased Electricity	**$170.1**	$165.4	$167.3	$ 4.7	2.1%	$(1.9)	(0.8%)
Conservation & Load Management	**2.6**	3.4	3.6	(0.8)	(0.4%)	(0.2)	(0.1%)
Total Cost of Electric Sales	**$172.7**	$168.8	$170.9	$ 3.9	1.7%	$(2.1)	(0.9%)
Electric Sales Margin	**$ 54.8**	$ 56.2	$ 54.3	$(1.4)	(0.6%)	$ 1.9	0.8%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues increased by $2.5 million, or 1.1%, in 2008 compared to 2007. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation and Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in 2008 reflects higher Purchased Electricity costs of $4.7 million offset by lower C&LM revenues of $0.8 million and lower sales margin of $1.4 million.

Purchased Electricity and C&LM revenues increased $3.9 million, or 1.7%, of Total Electric Operating Revenues in 2008 compared to 2007, primarily reflecting higher electric commodity prices, partially offset by lower sales volumes and lower spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin decreased $1.4 million in 2008 compared to 2007. The decrease in electric sales margin primarily reflects lower sales volumes, partially offset by higher electric base rates implemented in March of 2008. Total electric sales decreased 2.7% in 2008 compared to 2007 driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

Total Electric Operating Revenues decreased by $0.2 million, or 0.1%, in 2007 compared to 2006. The net decrease in Total Electric Operating Revenues in 2007 reflects lower Purchased Electricity costs of $1.9 million and lower C&LM revenues of $0.2 million, offset by higher sales margin of $1.9 million.

Electric sales margin increased $1.9 million in 2007 compared to 2006. The improvement in electric sales margin reflects higher average distribution rates in 2007 compared to 2006, partially offset by lower sales volumes due to milder summer temperatures this year, energy conservation by customers in response to higher overall energy prices and a slowing economy.

Gas Sales, Revenues and Margin

Therm Sales—Overall, Unitil's total therm sales of natural gas increased 66.2% in 2008 compared to 2007. Excluding the contribution of the acquisition of Northern Utilities, total therm sales of natural gas increased 1.1% in 2008 compared to 2007, reflecting a decrease of 2.0% in sales to residential customers offset by an increase of 2.7% in sales to C&I customers. The lower sales to residential customers in 2008 reflects a milder winter heating season earlier this year and lower average usage by our customers reflecting a slowing economy and energy conservation. The increase in gas sales to C&I customers in 2008 reflects increased usage of natural gas in those customers' production operations.

Unitil's total therm sales of natural gas increased 7.6% in 2007 compared to 2006. The increase in gas sales in 2007 reflects a colder winter heating season in 2007 compared to 2006 and higher natural gas sales to C&I customers. In 2007, natural gas sales to residential customers increased 4.1% compared to 2006 driven by the colder winter weather. Sales to C&I customers increased 9.6% compared to 2006, primarily due to a special contract with a large industrial customer.

The following table details total therm sales for the last three years, by major customer class:

Therm Sales (millions)

				2008 vs. 2007		2007 vs. 2006	
	2008	**2007**	**2006**	**Change**	**Change %**	**Change**	**Change %**
Residential	**13.3**	10.2	9.8	3.1	30.4%	0.4	4.1%
Commercial / Industrial	**33.9**	18.2	16.6	15.7	86.3%	1.6	9.6%
Total	**47.2**	28.4	26.4	18.8	66.2%	2.0	7.6%

Gas Operating Revenues and Sales Margin—The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenues and Sales Margin (millions)

				2008 vs. 2007		2007 vs. 2006	
	2008	**2007**	**2006**	**$ Change**	**% Change(1)**	**$ Change**	**% Change(1)**
Gas Operating Revenue:							
Residential	**$27.5**	$18.8	$17.2	$ 8.7	25.4%	$ 1.6	4.8%
Commercial / Industrial	**29.4**	15.4	16.1	14.0	41.0%	(0.7)	(2.1%)
Total Gas Operating Revenue	**$56.9**	$34.2	$33.3	$22.7	66.4%	$ 0.9	2.7%
Cost of Gas Sales:							
Purchased Gas	**$37.3**	$21.3	$22.4	$16.0	46.8%	$(1.1)	(3.3%)
Conservation & Load Management	**0.2**	0.2	0.2	—	—	—	—
Total Cost of Gas Sales	**$37.5**	$21.5	$22.6	$16.0	46.8%	$(1.1)	(3.3%)
Gas Sales Margin	**$19.4**	$12.7	$10.7	$ 6.7	19.6%	$ 2.0	6.0%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $22.7 million, or 66.4%, in 2008 compared to 2007, largely reflecting the acquisition of Northern Utilities and Granite State on December 1, 2008 and the 1.1% increase in gas sales, net of the effect of the acquisitions, and higher rates implemented in November 2007. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The increase in Total Gas Operating Revenues in 2008 reflects higher Purchased Gas costs of $16.0 million and higher sales margin of $6.7 million.

Purchased Gas and C&LM revenues increased $16.0 million, or 46.8%, of Total Gas Operating Revenues in 2008 compared to 2007, largely reflecting the acquisition of Northern Utilities and Granite State on December 1, 2008 as well as higher natural gas commodity prices. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $6.7 million in 2008 compared to 2007. This increase reflects $5.4 million of gas sales margin from Northern Utilities and Granite State and an additional increase of $1.3 million in gas sales margin reflecting higher rates implemented in November 2007 and higher sales to C&I customers.

Total Gas Operating Revenues increased $0.9 million, or 2.7%, in 2007 compared to 2006. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The increase in Total Gas Operating Revenues in 2007 reflects higher sales margin of $2.0 million, partially offset by lower Purchased Gas costs of $1.1 million.

Natural gas sales margin increased $2.0 million in 2007 compared to 2006 reflecting higher sales and new natural gas distribution rates approved and implemented in November 2007.

Operating Revenue—Other

Total Other Revenue increased $0.1 million in 2008 compared to 2007 and $1.3 million in 2007 compared to 2006. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (millions)

				2008 vs. 2007		2007 vs. 2006	
	2008	**2007**	**2006**	**$ Change**	**% Change**	**$ Change**	**% Change**
Usource	**$3.8**	$3.7	$2.4	$0.1	2.7%	$1.3	54.2%
Total Other Revenue	**$3.8**	$3.7	$2.4	$0.1	2.7%	$1.3	54.2%

Operating Expenses

Purchased Electricity—Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity increased $4.7 million, or 2.8%, in 2008 compared to 2007. This increase reflects higher electric commodity prices partially offset by lower sales volumes. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not affect earnings.

In 2007, Purchased Electricity expenses decreased $1.9 million, or 1.1%, compared to 2006 due lower electric kWh sales and an increase in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by higher electric commodity prices.

Purchased Gas—Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $16.0 million, or 75.1%, in 2008 compared to 2007. The increase in Purchased Gas largely reflects the acquisition of Northern Utilities and Granite State on December 1, 2008. In addition to the increase in Purchased Gas due to the acquisitions, Purchased Gas increased $1.5 million, or 7.0%, in 2008 compared to 2007 reflecting higher natural gas commodity prices and higher sales to C&I customers. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

In 2007, Purchased Gas decreased by $1.1 million, or 4.9%, compared to 2006, reflecting lower gas commodity prices and an increase in the amount of natural gas purchased by customers directly from third party suppliers, partially offset by increased therm sales.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. Total O&M expenses increased $1.3 million, or 5.0%, in 2008 compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.9 million of the increase. In addition, the increase in O&M expenses reflects higher employee and retiree compensation and benefit expenses of $2.7 million, including increased employee benefits of $1.4 million, driven primarily by higher medical claims in 2008 and higher employee benefits related to staffing increases, and higher salaries and compensation of $1.3 million, due to normal annual increases and staffing additions. Also contributing to the increase in O&M expenses were higher utility operating costs of $0.3 million and higher bad debt expenses of $0.3 million, partially offset by a reduction of $2.8 million from the proceeds of an insurance settlement and lower professional fees of $0.1 million.

In 2007, total O&M expense increased $0.5 million, or 1.9%, compared to 2006. This increase reflects higher employee and retiree compensation and benefit expenses of $0.8 million, including higher retiree benefit costs of $0.9 million, driven by higher pension and other postretirement benefit costs, and higher salaries and compensation of $0.8 million due to normal annual increases, partially offset by lower employee benefit costs of $0.9 million, driven by lower medical insurance costs. Also contributing to the increase in O&M expense were higher bad debt expenses of $0.1 million and an increase in all other operating expenses of $0.2 million, net, offset by lower distribution utility operating expenses of $0.6 million.

Conservation & Load Management—Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total Conservation & Load Management expenses decreased by $0.8 million, in 2008 compared to 2007. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total Conservation & Load Management expenses decreased $0.2 million in 2007 compared to 2006.

Depreciation and Amortization—Depreciation and Amortization expense increased $1.3 million, or 7.3% in 2008 compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.6 million of the increase. In addition, the increase in Depreciation and Amortization expense reflects the amortization, in the first quarter of 2008, of $0.7 million of natural gas inventory carrying costs deferred under a previous regulatory ruling, and higher depreciation on normal utility plant additions. Partially offsetting these increases were lower amortization costs of $0.8 million of information systems related costs.

In 2007, Depreciation and Amortization expense increased $1.7 million, or 10.6%, compared to 2006, reflecting higher depreciation on normal utility plant additions in 2007.

Local Property and Other Taxes—Local Property and Other Taxes increased by $0.9 million, or 16.1%, in 2008 compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.3 million of the increase. In addition, the increase in Local Property and Other Taxes reflects higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

In 2007, Local Property and Other Taxes increased by $0.1 million, or 1.8% compared to 2006. This increase was due to higher local property tax rates on higher levels of utility plant in service and higher payroll taxes.

Federal and State Income Taxes—Federal and State Income Taxes decreased by $0.1 million in 2008 compared to 2007 due to a lower effective tax rate year over year due to the recognition of higher permanent book/tax differences, including higher tax credits and prior year tax return true-up adjustments, in the third quarter of 2008, partially offset by higher pre-tax operating income in 2008 compared to 2007.

Federal and State Income Taxes increased by $0.2 million in 2007 compared to 2006 due to higher pre-tax operating income in 2007 compared to 2006.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) increased by $0.1 million in 2008 compared to 2007. This change reflects an adjustment of $0.1 million in conjunction with the Company's electric base distribution rate increase in Massachusetts which was implemented in March of 2008.

Other Non-operating Expenses (Income) increased by $0.2 million in 2007 compared to 2006. This change reflects the recognition in 2006 of a gain on the sale of land and timber harvest revenue.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated (See Note 5 to the accompanying Consolidated Financial Statements).

Interest Expense, Net increased $0.9 million in 2008 compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.3 million of the increase. The increase associated with the acquisitions is due to $0.5 million of interest expense from the issuance of long-term notes by Northern Utilities and Granite State in December 2008, partially offset by interest income on regulatory mechanisms. In addition to the increase related to the acquisitions, the remaining $0.6 million increase in Interest Expense, Net reflects higher debt outstanding and lower interest earned on regulatory assets compared to the prior period.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

In 2007, Total Interest Expense, net, rose by $1.8 million compared to 2006. This increase principally reflects the issuance of new long-term debt by Unitil on May 2, 2007. Unitil issued and sold $20 million of Senior Long-Term Notes at a coupon rate of 6.33%, through a private placement to institutional investors. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's distribution utilities. The resulting reduction in average daily short-term bank borrowings lowered short-term interest expense for the year which partially offset the increase in long-term interest expense.

LIQUIDITY, COMMITMENTS AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

The continued availability of various methods of financing, as well as the choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of earnings, cash flows, financial position; and the competitive pricing offered by financing sources.

The Company, along with its subsidiaries, are individually and collectively members of the Unitil Cash Pool (the Cash Pool). The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing.

The Cash Pool allows for an efficient exchange of cash among the Company and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on actual interest costs from lenders under the Company's revolving line of credit. At December 31, 2008 and 2007, all of the Company's subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

On December 1, 2008, the Company acquired all of the outstanding stock of Northern Utilities and Granite State for $160 million plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. The Company initially financed the Acquisitions and the related costs and expenses using borrowings under a bank financing facility with the Royal Bank of Canada. During December 2008, the Company repaid a portion of the bank financing facility using the net proceeds from: (i) the offering of the Company's common stock issued on December 15, 2008; (ii) the sale and issuance by Northern Utilities to institutional investors in a private placement of $80 million aggregate principal amount of long-term unsecured Notes on December 3, 2008; (iii) the sale and issuance by Granite State to institutional investors in a private placement of $10 million aggregate principal amount of long-term unsecured notes on December 15, 2008; and (iv) the receipt of proceeds from the financing by Northern Utilities of its gas storage inventory contemporaneously with the closing of the Acquisitions. At December 31, 2008, the amount remaining under the bank financing facility was $39.1 million. The Company expects to repay the outstanding balance under the bank financing facility prior to its maturity date of November 1, 2009 by issuing additional equity or debt. The bank financing facility contains customary terms and conditions for credit facilities of this type, including financial covenants. As of December 31, 2008, the Company was in compliance with the financial covenants contained in the bank financing facility.

At December 31, 2008 and December 31, 2007, Unitil had an aggregate of $35.0 million and $18.8 million, respectively, in short-term debt outstanding through bank borrowings (excluding amounts borrowed under the bank financing facility discussed above). On November 26, 2008, Unitil entered into a $60 million, 364-day revolving credit agreement with Bank of America, N.A., as administrative agent, and a syndicate of bank lenders. This facility replaces certain bilateral credit agreements with Bank of America, N.A., and RBS Citizens, N.A. The revolving credit agreement contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter. The revolving credit agreement also contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of December 31, 2008, the Company was in compliance with financial covenants contained in the revolving credit agreement.

On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. As part of this offering, the Company granted the underwriters a 30-day over-allotment option to purchase additional shares. The underwriters exercised the over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net proceeds were approximately $43 million (after payment of the underwriting discount, but excluding estimated offering expenses) and were used to repay a portion of the bank financing for the Company's acquisition of Northern Utilities and Granite State, as discussed above, and to repay other short-term indebtedness.

In connection with the Acquisitions, Northern Utilities issued $80.0 million aggregate principal amount of senior unsecured notes on December 3, 2008, and Granite State issued $10.0 million aggregate principal amount of senior unsecured notes on December 15, 2008. The net proceeds from the Northern Utilities and Granite State notes were used to recapitalize Northern Utilities and Granite State and to ultimately repay a portion of the Company's short-term bank financing facility used to fund the purchase price of the Acquisitions. The notes consist of:

(i) $30.0 million aggregate principal amount of 6.95% senior unsecured notes of Northern Utilities, which are due in 2018;

(ii) $50.0 million aggregate principal amount of 7.72% senior unsecured notes of Northern Utilities, which are due in 2038; and

(iii) $10.0 million aggregate principal amount of 7.15% senior unsecured notes of Granite State, which are due in 2018, along with a guarantee from Unitil for the payment of principal, interest and other amounts payable on the Granite State notes. This guarantee will terminate if Granite State is reorganized and merges with and into Northern Utilities.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2008.

		Payments Due by Period			
Significant Contractual Obligations (millions) as of December 31, 2008	**Total**	**2009**	**2010-2011**	**2012-2013**	**2014 & Beyond**
Long-term Debt	$249.7	$ 0.4	$ 0.9	$ 1.0	$247.4
Interest on Long-term Debt	302.0	17.9	35.8	35.6	212.7
Gas Supply Contracts[1]	189.2	72.9	66.6	49.7	—
Power Supply Contract Obligations	52.7	18.1	22.1	9.6	2.9
Other	4.8	1.3	2.1	0.9	0.5
Total Contractual Cash Obligations	$798.4	$110.6	$127.5	$96.8	$463.5

(1) Primarily reflects demand charges associated with natural gas transportation contracts.

The Company and its subsidiaries have material energy supply commitments that are discussed in Note 6 to the accompanying Consolidated Financial Statements. Cash outlays for the purchase of electricity and natural gas to serve customers are subject to reconciling recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over collected cash over subsequent of less than a year.

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2008 there were $18.0 million of guarantees outstanding and these guarantees extend through October 31, 2009. Of this amount, $15 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed below.

On November 1, 2008, Northern Utilities entered into a gas storage management agreement (the Agreement) pursuant to which (i) Northern Utilities released certain pipeline and storage capacity to an asset manager from November 1, 2008 through April 30, 2009 and (ii) the asset manager financed inventories associated with the released storage capacity from Northern Utilities contemporaneously with the closing of the Acquisitions. The Agreement requires Northern Utilities to repurchase quantities of natural gas over the course of the 2008/2009 winter heating season at a specified price and any remaining balance of the gas inventory on April 30, 2009 at the same price initially paid by the asset manager. The Agreement provides for the Company to issue a guarantee of payment of $15 million for the term of the agreement. There is $24.0 million outstanding at December 31, 2008 related to this Agreement included in Gas Supply Contracts in the Significant Contractual Obligations table above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2008, the principal amount outstanding for the 8% Unitil Realty notes was $4.7 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite State notes due 2018, as described above. As of December 31, 2008, the principal amount outstanding for the 7.15% Granite State notes was $10 million. This guarantee will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Benefit Plan Funding

The Company, along with its subsidiaries (other than Northern Utilities and Granite State), made cash contributions to its Pension Plan in the amount of $2.8 million and $2.8 million in 2008 and 2007, respectively. The Company, along with is subsidiaries (other than Northern Utilities and Granite State), contributed \$2.7 million and \$2.5 million to Voluntary Employee Benefit Trusts (VEBT) in 2008 and 2007, respectively. The Company expects to contribute approximately \$4.0 million and \$2.7 million, respectively to fund its Pension and PBOP Plans in 2009. The Company, along with its subsidiaries, expects to continue to make contributions to its Pension Plan and the VEBTs in future years in amounts consistent with the amounts recovered in the distribution utilities' rates for these other postretirement benefit costs. (See Note 10 to the accompanying Consolidated Financial Statements.)

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements. (See Note 5 to the accompanying Consolidated Financial Statements.)

Cash Flows

On December 1, 2008, the Company acquired Northern Utilities and Granite State. Cash flow results for 2008 include one month of activity for the acquired companies, which contributed to the increase in cash flow period over period. Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for 2008 and 2007.

(millions)	**2008**	**2007**
Cash Provided by Operating Activities	**\$47.3**	\$26.8

Cash Provided by Operating Activities—Cash Provided by Operating Activities was \$47.3 million in 2008, an increase of \$20.5 million over the comparable period in 2007. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes, was \$36.2 million in 2008, a \$10.6 million increase over 2007. Working Capital changes in Current Assets and Liabilities required a \$0.7 million use of cash in 2008, an increase in sources of cash of \$3.9 million compared to 2007. Deferred Restructuring Charges provided \$2.6 million and \$3.5 million in cash in 2008 and 2007, respectively, reflecting a net decrease of cash flows of \$0.9 million for the collection of deferred costs related to utility industry restructuring. All other items resulted in net sources of cash of \$9.2 million and \$2.3 million in 2008 and 2007, respectively.

(millions)	**2008**	**2007**
Cash (Used in) Investing Activities	**\$(238.2)**	\$(32.5)

Cash (Used in) Investing Activities—Cash used in Investing Activities was \$238.2 million for 2008, an increased use of cash of \$205.7 million over 2007, of which \$209.9 million was for the Company's acquisitions of Northern Utilities and Granite State on December 1, 2008. The purchase price of the acquisitions was \$160 million plus \$49.2 million for working capital, including approximately \$30 million of natural gas storage inventory. As part of the Acquisitions, the Company acquired cash of \$6.9 million and incurred transition and transaction costs of \$7.6 million. Capital expenditures for utility property, plant and equipment were \$28.3 million in 2008 compared to \$32.5 million in 2007, a decrease of \$4.2 million. Capital expenditures for ongoing electric and gas operations reflect normal utility plant additions, which were \$5.0 million lower in 2008 mainly due to the funding in 2007 of the Advanced Metering Infrastructure project.

(millions)	**2008**	**2007**
Cash Provided by Financing Activities	**\$197.8**	\$5.7

Cash Provided by Financing Activities—Cash provided by Financing Activities was \$197.8 million in 2008, an increase of \$192.1 million compared to 2007. Sources of cash primarily reflect the financing activity related to the Company's acquisitions of Northern Utilities and Granite State on December 1, 2008. These financing activities (discussed above) included proceeds from the issuance of common stock, the sale and issuance of senior unsecured notes and a bank financing facility. In addition, Cash Provided by Financing Activities also reflect the financing of Northern Utilities' gas inventory and the issuance of short-term debt to fund utility plant additions and working capital requirements. Uses of cash for financing activities primarily reflect regular quarterly dividend payments on common and preferred stock of $8.1 million, and the scheduled repayment of long-term debt of $0.4 million.

FINANCIAL COVENANTS AND RESTRICTIONS

The agreements under which the Company's and its subsidiaries' long-term debt were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations and covenants restricting the ability to (i) pay dividends, (ii) incur indebtedness and liens, (iii) merge or consolidate with another entity or (iv) sell, lease or otherwise dispose of all or substantially all assets. (See Note 5 to the accompanying Consolidated Financial Statements.)

The long-term debt and preferred stock of Unitil, Unitil Energy, Fitchburg, Northern Utilities, Granite State and Unitil Realty are privately held, and the Company does not issue commercial paper. For these reasons, the debt securities of Unitil and its subsidiaries are not publicly rated.

The Company financed the Acquisitions and the related costs and expenses in part using borrowings under a bank financing facility, as described above. As of December 31, 2008, there was $39.1 million outstanding on this bank financing facility. The bank financing facility contains customary terms and conditions, including, without limitation, covenants restricting the Company's ability to (i) pay dividends, (ii) incur indebtedness and liens, (iii) merge or consolidate with another entity or (iv) sell, lease or otherwise dispose of all or substantially all assets.

On November 26, 2008, Unitil entered into a $60 million, 364-day revolving credit agreement. The revolving credit agreement contains customary terms and conditions for credit facilities of this type, including certain financial covenants, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter.

The Company and its subsidiaries are currently in compliance with all such covenants in these debt instruments.

DIVIDENDS

Unitil's annualized common dividend was $1.38 per common share in 2008, 2007 and 2006. Unitil's dividend policy is reviewed periodically by the Board of Directors. Unitil has maintained an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2009 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

LEGAL PROCEEDINGS

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. The complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. As of this date the complaint has not been served on Fitchburg. The Company believes this complaint is without merit, and will defend itself vigorously.

REGULATORY MATTERS

Overview (Unitil Energy, Fitchburg, and Northern Utilities)—Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next two to four years, is $81.9 million as of December 31, 2008 including $22.1 million in Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans. See Note 7 for additional information on these filings.

Unitil Energy—On January 22, 2008, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. The NHPUC determined that it is appropriate to implement some form of time-based metering standards and ordered that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes are to be determined in separate proceedings initiated by the NHPUC. The NHPUC also found that additional review of the energy standards for net metering, fuel diversity and fossil fuel generation efficiency as proposed in the Energy Policy Act of 2005 is not required due to action of the New Hampshire legislature and the NHPUC in adopting comparable standards.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On January 16, 2009, the NHPUC issued its decision in this matter, concluding that such rate mechanisms should only be implemented on a company-by-company basis in the context of an examination of company specific costs and revenues, service territory, customer mix and rate base investment.

In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation.

Fitchburg—Electric Operations—The Company received a final order from the MDPU on February 29, 2008 approving an electric rate increase of $2.1 million, effective March 1, 2008.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Unitil was able to restore power to one-third of its Massachusetts customers within three days, and 80 percent of its customers by day seven, and the final Massachusetts customers, including those with individual service problems, were restored by day 13, December 24, 2008. On January 7, 2009, the MDPU opened an investigation into the preparation and response of the Massachusetts electric distribution companies to the December 12, 2008 Winter Storm. Each electric distribution company has been ordered to file a report detailing its response to the storm and outages, and its service restoration efforts with the MDPU by February 23, 2009. Public hearings have been held in each of the electric distribution utilities' service areas in Massachusetts. Based on its preliminary assessment, the Company has accrued and deferred approximately $10 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. This matter remains pending.

Fitchburg—Gas Operations—Fitchburg provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current distribution rates were approved by the MDPU in 2007. Fitchburg's customers may purchase natural gas supplies from third-party vendors or purchase their natural gas from Fitchburg as the provider of last resort. Fitchburg collects its natural gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

Fitchburg—Other—On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, including company specific rate cases. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012. Each distribution company was required to notify the MDPU of when the company expects to file a rate case to implement decoupling. Fitchburg notified the MDPU that it will be prepared to file rate cases for each of its divisions by the third quarter of 2009, based upon a calendar 2008 test year, along with a comprehensive decoupling proposal and associated base rate adjustment mechanism. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "*The Green Communities Act*" (the GC Act), an energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act includes provisions that:

- Require electric and natural gas distribution companies to file three-year energy efficiency investment plans designed to implement all available cost-effective energy efficiency and demand reduction resources; the plans are to include fully reconciling funding mechanisms;
- Require utility distribution companies to undertake various Green programs, including the solicitation of bids for long-term renewable energy procurement contracts for which utilities would be allowed remuneration on certain contract commitments;

- Establishes expanded authority for the MDPU to investigate mergers involving holding companies of public utilities;
- Increase the Renewable Portfolio Standard by 1% annually, requiring that by the year 2020 utilities and other electricity suppliers obtain 15% of the power they sell from renewable resources;
- Authorize electric distribution companies to construct, own, and operate up to 50 megawatts of solar generating capacity; and
- Modify the service quality performance penalty provision.

The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs.

Northern Utilities Acquisition: On December 1, 2008 Unitil completed the purchase of Northern Utilities from Bay State and Granite State from NiSource. Joint petitions on behalf of Unitil and Northern Utilities requesting approval of the purchase of Northern Utilities by Unitil were filed with the NHPUC and the MPUC on March 31, 2008. State regulatory approvals of Unitil's purchase of Granite State were not required. In August 2008, unopposed settlement agreements resolving all outstanding issues and recommending approval of the acquisition were filed with the MPUC and NHPUC on behalf of Unitil, Northern Utilities and the active parties to the respective Maine and New Hampshire proceedings. The NHPUC approved the transaction on October 10, 2008. The MPUC issued an order approving the transaction on November 5, 2008.

Although separately negotiated and filed with the MPUC and the NHPUC, the settlement agreements reflect several common topics (including regulatory authorizations, matters affecting rates, customer service provisions, service quality, gas safety and reliability, agreements regarding Granite State and reporting requirements) as follows:

The settlement agreements include the following authorizations and approvals:

- approval of Unitil's acquisition of Northern Utilities;
- approval of the amended Unitil Service Agreement adding Northern Utilities as a party;
- approval of the amended Unitil Cash Pooling Agreement adding Northern Utilities as a party; and
- approval of Northern Utilities' accounting deferral and 10-year amortization of transaction costs and transition costs resulting from the Company's acquisition of Northern Utilities and the Company's agreement not to seek recovery of these costs, or the transaction or transition costs of any other utility subsidiary, in rates.

The settlement agreements include the following commitments related to rates:

- agreement that synergy savings resulting from our acquisition of Northern Utilities will be retained by the Company until the next base rate change and then will flow to customers;
- agreement not to request a base rate change for Northern Utilities before November 1, 2010 unless (i) Northern Utilities' projected annual revenues are more than 8% below the level of total 2007 distribution revenues or (ii) the MPUC or NHPUC, as applicable, approves a plan to subject Granite State's rates to state regulation;
- agreement to allow Northern Utilities to recover prudently incurred integration costs for capitalized expenditures to build or upgrade systems or facilities required to independently operate Northern Utilities;
- agreement not to seek recovery in Northern Utilities' rates of any acquisition premium resulting from Unitil's acquisition of Northern Utilities and that any acquisition adjustment (positive or negative) shall be accounted for below the line for ratemaking purposes over a 10-year period;
- agreement to hold Northern Utilities' customers harmless for the elimination of historical accumulated deferred income tax (ADIT) liabilities resulting from its Internal Revenue Service Section 338(h)(10) election;

- agreement to use an imputed weighted cost of debt for ratemaking purposes until Northern Utilities' existing debt instruments would have matured; and

- agreement not to change Northern Utilities' existing depreciation rates for its Maine division until approved in the next general rate case.

The settlement agreements also contain the following commitments related to customers:

- agreement to implement a Low Income Program for Northern Utilities' Maine division, to provide additional customer payment options (including credit or debit cards and by internet and telephone) for Maine customers and to continue low income programs in Northern Utilities' New Hampshire division;
- agreement to review with the parties to the settlements communications that we develop to inform Northern Utilities' customers about our acquisition of Northern Utilities and to keep them apprised of the transition; and
- with respect to Maine, agreement to conduct a study of alternatives for the sale, lease, or use of the unused Portland manufactured gas site property that would best serve ratepayers' interests.

The settlement agreements contain the following commitments related to service quality, gas safety and reliability:

- agreement to improve and adhere to Northern Utilities' existing service quality plans in each jurisdiction; and
- agreement to provide notifications and safety reports based on several service quality and gas safety metrics, as well as implementing gas operations programs and practices.

The settlement agreements contain the following commitments related to Granite State:

- agreement to work collaboratively with the parties to the settlements to design and to conduct a comprehensive study of the issues and costs for modification of the physical, operational, regulatory, and corporate structure necessary for state regulation of Granite State and to provide a report within one year of the closing; and
- authorization for Northern Utilities to execute a firm service contract with Granite State for 100,000 Dekatherms (Dth) of capacity at Granite State's current recourse rate of $1.6666/ Dth for the period November 1, 2008 through October 31, 2010.

The settlement agreements contain the following commitments regarding affiliate books and records and transaction reporting:

- agreement to provide timely access to the books and records of any of Northern Utilities' affiliates at the discretion of the MPUC or the NHPUC, as applicable;
- agreement to file reports on our transition progress, business integration, costs, the Transition Services Agreement and costs while our acquisition of Northern Utilities was pending; and
- agreement to notify the MPUC and the NHPUC of any substantial changes in the financing terms.

In Massachusetts, the GC Act expanded the authority of the MDPU to review holding company mergers and sales of subsidiaries to determine how such transactions would affect the holding companies' Massachusetts' utility operating companies and their ratepayers. Unitil and Bay State filed a joint Petition with the MDPU on August 13 seeking an advisory determination that the recent statutory amendment was inapplicable to the proposed sale, or, alternatively, sought approval of the proposed sale. The MDPU declined to issue the advisory ruling, and determined that it had the requisite authority to review the transaction. After investigation and hearing, the MDPU issued its approval of the transaction on November 18, 2008.

Northern Utilities—Notices of Probable Violation—Beginning in October 2007, the MPUC initiated formal investigations into a number of Notices of Probable Violation (NOPVs) alleging that Northern

Utilities had violated various provisions of the federal pipeline safety regulations, as adopted by the MPUC. Northern Utilities, the MPUC Staff and Unitil filed a comprehensive settlement (Settlement), which was approved by the MPUC on November 21, 2008, resolving these matters. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for certain safety related improvements for which no rate recovery will be allowed and obligations to be undertaken for Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at December 31, 2008 was $3.1 million.

Northern Utilities—NH 2007/2008 Winter Cost of Gas—On October 31, 2007, the NHPUC issued Order No. 24,798 concerning the 2007/2008 winter cost of gas proceeding for Northern Utilities' New Hampshire division. In that order, the NHPUC noted that Northern Utilities had identified an unusually high level of lost and unaccounted for gas (UAFG), and ordered Northern Utilities to file a detailed report concerning its investigation of this matter. Through its investigation, Northern Utilities determined that the unaccounted for gas affected both its New Hampshire and Maine divisions, and that the cause appeared to be incorrect metering at the Maritimes & Northeast (M&NE) / Portland Natural Gas Transmission System's (PNGTS) Newington Gate Station caused by an erroneous meter module change. The metering equipment was operated and maintained by a third party, Spectra Energy, the parent company of M&NE. PNGTS and M&NE share joint ownership of the section of the pipeline connected to Granite State at the Newington Gate Station. The error caused Granite State to be billed for 758,702 Dth of natural gas, with Granite State then billing Northern Utilities for an equivalent amount, although the volumes of gas were not actually consumed. The meter error was corrected and Northern Utilities, Granite State, Spectra Energy and PNGTS reached an agreement whereby PNGTS will provide to Northern Utilities, through Granite State, gas volumes equal to the misread amounts to correct for the error, over a period of approximately 18 months. Both the NHPUC and the MPUC have approved this arrangement, as well as Northern Utilities' methodology for allocating the gas received to its Maine and New Hampshire divisions based upon the actual gas use over the period the meters were misread. As of December 31, 2008, Northern Utilities has recorded approximately $4.0 million reflecting the anticipated liability of the future refund amount based on current market prices with an offsetting receivable from Granite State.

See Note 7 to the accompanying Consolidated Financial Statements for additional information on Regulatory Matters.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2008, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former MGP site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800s through the mid 1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

See Note 7 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES AND EMPLOYEE RELATIONS

As of December 31, 2008, the Company and its subsidiaries had 406 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2008, 144 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two of these agreements expire on March 31, 2009, two agreements expire on May 31, 2010, and one agreement expires on June 5, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or “regulatory assets” under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or “regulatory liabilities” under SFAS No. 71.

The Company’s principal regulatory assets and liabilities are detailed on the Company’s Consolidated Balance Sheet and a summary of the Company’s Regulatory Assets is provided in Note 1 thereto. The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company’s consolidated financial statements.

The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, “Regulated Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71.” In the Company’s opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company’s experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company’s distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company’s experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans”, (SFAS No. 158), an amendment of SFAS No. 87, “Employers’ Accounting for Pensions”, SFAS No. 88, “Employers’ Accounting for Settlements and Curtailments of

Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2008 and 2007, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2008 and 2007, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $675,000 and $690,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $531,000 and $539,000, respectively. (See Note 10 to the accompanying Consolidated Financial Statements).

Income Taxes—Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) and under FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109.

Depreciation—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2008, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements' in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, “Summary of Significant Accounting Policies,” Note 9, “Income Taxes,” Note 6, “Energy Supply,” Note 10, “Benefit Plans,” and Note 7, “Commitment and Contingencies,” to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please also refer to Item 1A. “Risk Factors”.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 3.8%, 5.6%, and 5.5% during 2008, 2007, and 2006, respectively.

MARKET RISK

Although Unitil’s three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets of Unitil Corporation and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the years ended December 31, 2008, 2007 and 2006. We also have audited Unitil Corporation and subsidiaries' internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Northern Utilities, Inc. and Granite State Gas Transmission, Inc., businesses acquired by the Company during the year ended December 31, 2008, which are included in the 2008 consolidated financial statements of the Company and constituted approximately $273.7 million and $161.2 million of total and net assets, respectively, as of December 31, 2008 and approximately $22.2 million and $1.9 million of revenues and net income respectively, for the year ended December 31, 2008. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Northern Utilities, Inc. and Granite State Gas Transmission, Inc.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unitil Corporation and subsidiaries as of December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Unitil Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Vitale, Caturano & Company, P.C.

Boston, Massachusetts
February 13, 2009

[THIS PAGE INTENTIONALLY LEFT BLANK]

CONSOLIDATED STATEMENTS OF EARNINGS

(Millions, except common shares and per share data)

Year Ended December 31,	2008	2007	2006
Operating Revenues:			
Electric	**$227.5**	$225.0	$225.2
Gas	**56.9**	34.2	33.3
Other	**3.8**	3.7	2.4
Total Operating Revenues	**288.2**	262.9	260.9
Operating Expenses:			
Purchased Electricity	**170.1**	165.4	167.3
Purchased Gas	**37.3**	21.3	22.4
Operation and Maintenance	**27.5**	26.2	25.7
Conservation & Load Management	**2.8**	3.6	3.8
Depreciation and Amortization	**19.1**	17.8	16.1
Provisions for Taxes:			
Local Property and Other	**6.5**	5.6	5.5
Federal and State Income	**4.4**	4.5	4.3
Total Operating Expenses	**267.7**	244.4	245.1
Operating Income	**20.5**	18.5	15.8
Other Non-Operating Expenses	**0.3**	0.2	—
Income Before Interest Expense	**20.2**	18.3	15.8
Interest Expense, net	**10.5**	9.6	7.8
Net Income	**9.7**	8.7	8.0
Less Dividends on Preferred Stock	**0.1**	0.1	0.1
Earnings Applicable to Common Shareholders	**$ 9.6**	$ 8.6	$ 7.9
Average Common Shares Outstanding (000's)—Basic	**5,830**	5,659	5,597
Average Common Shares Outstanding (000's)—Diluted	**5,830**	5,672	5,612
Earnings per Common Share—Basic and Diluted	**$ 1.65**	$ 1.52	$ 1.41

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS *(Millions)*

ASSETS

December 31,	2008	2007
Utility Plant:		
Electric	**$289.0**	$266.2
Gas	**304.2**	67.8
Common	**30.5**	26.2
Construction Work in Progress	**17.7**	20.3
Utility Plant	**641.4**	380.5
Less: Accumulated Depreciation	**218.6**	131.6
Net Utility Plant	**422.8**	248.9
Current Assets:		
Cash	**11.5**	4.6
Accounts Receivable—(Net of Allowance for Doubtful Accounts of $3.0 and $1.3)	**39.7**	24.9
Accrued Revenue	**58.9**	36.7
Gas Inventory	**31.6**	2.7
Material and Supplies	**2.7**	1.8
Prepayments and Other	**5.9**	2.2
Total Current Assets	**150.3**	72.9
Noncurrent Assets:		
Regulatory Assets	**146.2**	146.5
Other Noncurrent Assets	**15.9**	6.3
Total Noncurrent Assets	**162.1**	152.8
TOTAL	**$735.2**	$474.6

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS ***(cont.)*** *(Millions)*

CAPITALIZATION AND LIABILITIES

December 31,	2008	2007
Capitalization:		
Common Stock Equity	**$139.5**	$100.4
Preferred Stock	**2.0**	2.1
Long-Term Debt, Less Current Portion	**249.3**	159.6
Total Capitalization	**390.8**	262.1
Current Liabilities:		
Long-Term Debt, Current Portion	**0.4**	0.4
Accounts Payable	**36.3**	17.6
Short-Term Debt	**74.1**	18.8
Energy Supply Contract Obligations	**42.0**	20.0
Other Current Liabilities	**35.8**	7.3
Total Current Liabilities	**188.6**	64.1
Deferred Income Taxes	**31.1**	33.4
Noncurrent Liabilities:		
Energy Supply Contract Obligations	**34.6**	52.7
Retirement Benefit Obligations	**67.4**	48.2
Environmental Obligations	**12.3**	12.0
Other Noncurrent Liabilities	**10.4**	2.1
Total Noncurrent Liabilities	**124.7**	115.0
TOTAL	**$735.2**	$474.6

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS (Millions)

Year Ended December 31,	2008	2007	2006
Operating Activities:			
Net Income	**$ 9.7**	$ 8.7	$ 8.0
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**19.1**	17.8	16.1
Deferred Taxes Provision	**7.4**	(0.9)	0.5
Changes in Current Assets and Liabilities:			
Accounts Receivable	**(6.4)**	(2.4)	1.1
Accrued Revenue	**(10.3)**	1.1	(4.9)
Accounts Payable	**11.4**	(2.2)	(0.8)
All Other Current Assets and Liabilities	**4.6**	(1.1)	0.8
Deferred Restructuring Charges	**2.6**	3.5	(2.0)
Other, net	**9.2**	2.3	1.6
Cash Provided by Operating Activities	**47.3**	26.8	20.4
Investing Activities:			
Property, Plant and Equipment Additions	**(28.3)**	(32.5)	(33.6)
Acquisitions, net (See Note 3)	**(209.9)**	—	—
Cash (Used In) Investing Activities	**(238.2)**	(32.5)	(33.6)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**55.3**	(7.2)	7.3
Proceeds from Issuance of Long-Term Debt	**90.0**	20.0	15.0
Repayment of Long-Term Debt	**(0.4)**	(0.3)	(0.3)
Net Increase in Gas Inventory Financing	**24.0**	—	—
Dividends Paid	**(8.1)**	(7.9)	(7.9)
Proceeds from Issuance of Common Stock	**37.4**	1.5	1.0
Other, net	**(0.4)**	(0.4)	(0.5)
Cash Provided by Financing Activities	**197.8**	5.7	14.6
Net Increase in Cash	**6.9**	—	1.4
Cash at Beginning of Year	**4.6**	4.6	3.2
Cash at End of Year	**$ 11.5**	$ 4.6	$ 4.6
Supplemental Information:			
Interest Paid	**$ 12.5**	$ 12.2	$ 10.7
Income Taxes Paid (Refunded)	**$ (0.5)**	$ 5.3	$ 3.1

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF
CHANGES IN COMMON STOCK EQUITY

(Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2006	$ 62.2	$34.1	**$ 96.3**
Net Income for 2006		8.0	**8.0**
Dividends		(7.8)	**(7.8)**
Shares Issued Under Stock Plans	0.3		**0.3**
Issuance of 40,365 Common Shares	1.0		**1.0**
Balance at December 31, 2006	63.5	34.3	**97.8**
Net Income for 2007		8.7	**8.7**
Dividends		(7.9)	**(7.9)**
Shares Issued Under Stock Plans	0.8		**0.8**
Issuance of 38,303 Common Shares	1.0		**1.0**
Balance at December 31, 2007	65.3	35.1	**100.4**
Net Income for 2008		9.7	**9.7**
Dividends		(8.0)	**(8.0)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 32,754 Common Shares	0.8		**0.8**
Issuance of 2,000,000 Common Shares (See Note 4)	36.2		**36.2**
Balance at December 31, 2008	**$102.7**	**$36.8**	**$139.5**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the Acquisitions). Bay State is a wholly owned subsidiary of NiSource.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the "distribution utilities").

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—In accordance with current accounting pronouncements, the Company's consolidated financial statements include the accounts of Unitil and all of its wholly owned subsidiaries and all intercompany transactions are eliminated in consolidation. The operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from December 1, 2008 through December 31, 2008.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)	December 31, 2008	December 31, 2007
Energy Supply Contract Obligations	**$ 52.7**	$ 72.7
Deferred Restructuring Costs	**28.3**	30.5
Generation-related Assets	**0.8**	1.6
Subtotal—Restructuring Related Items	**81.8**	104.8
Retirement Benefit Obligations	**45.5**	35.1
Income Taxes	**16.0**	14.6
Environmental Obligations	**19.7**	13.1
Other	**10.1**	2.9
Total Regulatory Assets	**$173.1**	$170.5
Less: Current Portion of Regulatory Assets (1)	**26.9**	24.0
Regulatory Assets—noncurrent	**$146.2**	$146.5

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. Under the Independent System Operator—New England (ISO-NE) Financial Assurance Policy (Policy), Unitil's affiliates Unitil Energy, Fitchburg and Unitil Power are required to provide assurance of their ability to satisfy their obligations to ISO-NE. Under this Policy, Unitil's affiliates provide cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2008 and 2007, the Unitil affiliates had deposited $3.7 million and $2.5 million, respectively to satisfy their ISO-NE obligations. In addition, Northern Utilities has cash margin deposits to satisfy requirements for its natural gas hedging program. On December 31, 2008, there was $7.0 million deposited for this purpose.

Goodwill and Intangible Assets—As a result of the acquisitions of Northern Utilities and Granite State, the Company recognized a bargain purchase adjustment as a reduction to Utility Plant, to be amortized over a ten year period, beginning with the date of the Acquisitions, as authorized by regulators. (See Note 3).

Off-Balance Sheet Arrangements—As of December 31, 2008, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases (See Note 5).

Investments and Trading Activities—The Company invests in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for accounting purposes.

Derivatives—The Company enters into wholesale electric and gas energy supply contracts to serve its customers. The Company's policy is to review each contract and determine whether they meet the criteria for classification as derivatives under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of SFAS No. 133" (SFAS No. 138), SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149), SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" and FASB Staff Position No. FAS 133-1 and FIN 45-4, "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of SFAS No. 133 and FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others", (FIN 45); and Clarification of the Effective Date of SFAS No. 161 (FSP FAS 133-1 and FIN 45-4). The Company has a regulatory approved hedging program, discussed below, which meets the criteria for classification as a derivative instrument. Additionally, the Company may enter into interest rate hedging transactions with respect to existing indebtedness and anticipated debt offerings. As of December 31, 2008, the Company has not entered into any interest rate hedging transactions. However, should the Company enter into any such transactions in the future, its policy will be to review each transaction and determine whether it meets the criteria for classification as derivatives under SFAS No. 133, SFAS No. 138 and / or SFAS No. 149.

The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases New York Mercantile Exchange futures that correspond to the associated delivery month. Any gains or losses on the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. As a result of the ratemaking process, the Company records gains and losses as regulatory liabilities or assets and recognizes such gains or losses in Purchased Gas when recovered in revenues. The Company's Consolidated Balance Sheets include derivative liabilities related to net unrealized losses on current futures contracts of \$4.5 million in Other Current Liabilities and on noncurrent futures contracts of \$1.2 million in Noncurrent Liabilities at December 31, 2008. These amounts are offset in Accrued Revenues on the Company's Consolidated Balance Sheets.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition—Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates. See Note 10.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company's policy is to record those estimates in accordance with the American Institute of Certified Public Accountants Statement of Position 94-6, "Disclosure of Certain Significant Risks and Uncertainties."

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5). SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2008, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below. (See Note 7).

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 4.58%, 5.73% and 4.92% in 2008, 2007 and 2006, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At December 31, 2008 and December 31, 2007, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation, including $17.4 million in 2008 related to Northern Utilities, is $33.9 million and $16.2 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the

Company’s fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. Depreciation provisions for Unitil’s utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2008 – 3.94%, 2007 – 4.29% and 2006 – 4.40%.

Environmental Matters—The Company’s past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has or will recover substantially all of the costs of the environmental remediation work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2008, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 7, Commitments and Contingencies. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company’s financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation using the fair value-based method as prescribed under FASB No. 123(R), “Share-Based Payment” (See Note 4).

Sales and Consumption Taxes—The Company bills its customers sales tax in Massachusetts and Maine and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company’s Consolidated Statements of Earnings.

Income Taxes—Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company’s current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company’s consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, “Accounting for Income Taxes” (SFAS No. 109) and under FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48), an interpretation of SFAS No. 109.

Dividends—The Company is currently paying a dividend at an annual rate of $1.38 per common share. The Company’s dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Other Recently Issued Pronouncements—On December 30, 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. FAS 132(R)-1, “Employers’ Disclosures about Postretirement Benefit Plan Assets”, (FSP FAS 132(R)-1) to provide guidance on an employers’ disclosures about plan assets of a defined benefit pension or other postretirement plan. The disclosures about plan assets required by FSP FAS 132(R)-1 are to be provided for fiscal years ending after December 15, 2009. The Company does not expect that the adoption of the deferred sections of FSP FAS 132(R)-1 will have an impact on the Company’s Consolidated Financial Statements.

On September 12, 2008, the FASB issued FASB Staff Position No. FAS 133-1 and FIN 45-4, “Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133, “Accounting for Derivative Instruments and Hedging Activities”, (SFAS No. 133) and FASB Interpretation No. 45, “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others”, (FIN 45); and Clarification of the Effective Date of FASB Statement No. 161, “Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133” (SFAS No. 161)”, (FSP FAS 133-1 and FIN 45-4). FSP FAS 133-1 and FIN 45-4 is effective for reporting periods ending after November 15, 2008, with early adoption permitted. FSP

FAS 133-1 and FIN 45-4 (i) amends SFAS No. 133 to require disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument, (ii) amends FIN 45 to require an additional disclosure about the current status of the payment/performance risk of a guarantee, and (iii) clarifies the FASB's intent about the effective date of SFAS No. 161. The Company adopted FSP FAS 133-1 and FIN 45-4 and there was no impact on its financial statements.

In May 2008, the FASB issued FASB Statement No. 162, "The Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 162), effective 60 days following the SEC's September 2008 approval of the Public Company Accounting Oversight Board's amendments to AU Section 411. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States. The Company adopted SFAS No. 162 and there was no impact on its financial statements.

In March 2008, the FASB issued SFAS No. 161, effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption allowed. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of an entity's use of derivative instruments and the effect of those derivative instruments on an entity's financial statements. The Company adopted SFAS No. 161 and there was no impact on its financial statements.

In December 2007, the FASB issued FASB Statement No. 141 (Revised 2007), "Business Combinations" (SFAS No. 141R), effective prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141R establishes principles and requirements on how an acquirer recognizes and measures in its financial statements identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree, goodwill or gain from a bargain purchase and accounting for transaction costs. Additionally, SFAS No. 141R determines what information must be disclosed to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The Company adopted SFAS No. 141R upon its effective date on January 1, 2009 and it will only impact future acquisitions, if any.

Reclassifications—Based on the Company's analysis certain amounts previously reported have been reclassified to conform to improve the financial statements' presentation and to conform to current year presentation, including the reclassification of $24.0 million of Noncurrent Assets to Current Assets and $20.0 million of Noncurrent Liabilities to Current Liabilities principally related to current collections and obligations of Regulatory Assets and Regulatory Liabilities for 2007.

Note 2: Subsequent Event—Issuance of Common Shares

As discussed in Note 3 below, on December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. As part of this offering, the Company granted the underwriters a 30-day over-allotment option to purchase additional shares. The underwriters exercised the over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increases to Common Equity and Cash from the over-allotment sales were approximately $5.1 million (after payment of the underwriting discount and offering expenses) and were used to repay a portion of the short-term indebtedness used for the Company's acquisitions of Northern Utilities and Granite State. The Company recorded the issuance of the 270,000 shares, the sale proceeds and the increase in Common Equity in January 2009.

Note 3: Acquisitions

On December 1, 2008, the Company purchased (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource pursuant to the Stock Purchase Agreement (SPA) dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. As part of the acquisition, the Company acquired cash of $6.9 million and incurred transition and transaction costs of $7.6 million.

The Company initially financed the Acquisitions and the related costs and expenses using borrowings under a bank financing facility with the Royal Bank of Canada. During December 2008, the Company repaid a portion of the bank financing facility using the net proceeds from: (i) the offering of the Company's common stock issued on December 15, 2008; (ii) the sale and issuance by Northern Utilities to institutional investors in a private placement of $80 million aggregate principal amount of long-term unsecured Notes on December 3, 2008; (iii) the sale and issuance by Granite State to institutional investors in a private placement of $10.0 million aggregate principal amount of long-term unsecured notes on December 15, 2008; and (iv) the receipt of proceeds from the financing by Northern Utilities of its gas storage inventory contemporaneously with the closing of the Acquisitions. At December 31, 2008, the amount remaining under the bank financing facility was $39.1 million. The Company expects to repay the outstanding balance under the bank financing facility prior to its maturity date of November 1, 2009 by issuing additional equity or debt.

The Company accounted for the Acquisitions under the purchase method of accounting for business combinations, in accordance with FASB Statement No. 141, "Business Combinations" (SFAS No. 141) and SFAS No. 71. In that process, the Company recognized and measured the identifiable assets acquired and the liabilities assumed. In compliance with SFAS No. 71 regulatory accounting, the Company carried forward the historical book amounts of Northern Utilities' and Granite State's utility plant and regulatory assets and liabilities. The remaining identifiable assets and liabilities have been recorded at fair value at the date of acquisition. Also, the Company measured and recognized an acquisition adjustment related to a bargain purchase relative to these values acquired against the purchase price. The results of Northern Utilities and Granite State have been included in the accompanying consolidated financial statements from the date of acquisition.

The following table represents the allocation of the total purchase price of Northern Utilities and Granite State to the acquired assets and liabilities of Northern Utilities and Granite State. The allocation represents the values assigned to each of the assets acquired and liabilities assumed. The purchase price allocation is preliminary and is subject to change due to several factors, including, but not limited to: (1) changes in the fair values of Northern Utilities' and Granite State's current assets and liabilities as of the date of the acquisition; (2) the actual transition and transaction costs incurred; and (3) changes in the Company's valuation estimates that may be made between now and the time the purchase price allocation is finalized.

Purchase Price Allocation
($ Millions)

	December 1, 2008
Equity Purchase Price	$ 160.0
Plus: Working Capital Adjustment	49.2
Aggregate Purchase Price	209.2
Transaction and Transition Costs	7.6
Total Cash Purchase Price	216.8
Allocation To:	
Book Value of Net Utility Plant	(196.0)
Cash Acquired	(6.9)
Accounts Receivable and Other Current Assets	(22.2)
Accrued Revenue	(9.4)
Gas Inventory	(32.3)
Regulatory Assets	(27.4)
Accounts Payable and Other Current Liabilities	17.8
Regulatory Liabilities	31.3
Plant Acquisition Adjustment	**$ (28.3)**

The Company will amortize, over a 10-year period, the transition and transaction costs co-terminus with the Plant Acquisition Adjustment.

Note 4: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

As of August 21, 2008 the Company's common stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's common stock will continue to trade under its current symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 7,791,617, and 5,740,023 of common shares outstanding at December 31, 2008 and December 31, 2007, respectively.

Unitil Corporation Common Stock Offering—On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. The Company repaid $36.8 million outstanding under the bank financing facility for the Company's acquisitions of Northern Utilities and Granite State with the net proceeds from the sale and issuance of its common stock.

As part of this offering, the Company granted the underwriters a 30-day over-allotment option to purchase additional shares. The underwriters exercised the over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the over-allotment sales were approximately $5.1 million (after payment of the underwriting discount, but excluding estimated offering expenses) and were used to repay a portion of the bank financing for the Company's acquisitions of Northern Utilities and Granite State and to repay other short-term indebtedness. The Company recorded the issuance of the 270,000 shares, the sale proceeds and the increase in Common Equity in January 2009.

Dividend Reinvestment and Stock Purchase Plan—During 2008, the Company sold 32,754 shares of its common stock, at an average price of $25.87 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $0.8 million were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's common stock and cash payments in additional shares of the Company's common stock. During 2007 and 2006, the Company raised $1.0 million and $1.0 million, respectively, of additional common equity through the issuance of 38,309 and 40,365 shares, respectively, of its common stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired—During 2008, 2007 and 2006, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. The Company has adopted FASB Statement No. 123(R), "Accounting for Stock Based Compensation," and recognizes compensation costs at fair value at the date of grant. Details of the plans are as follows:

Restricted Stock Plan—On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company common stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided for in the Plan. Awards fully vest over a period of four years at a rate of 25% each year.

During the vesting period, dividends on restricted shares underlying the award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit.

Restricted shares issued for 2006 – 2008 in conjunction with the Plan are presented in the following table:

Issuance Date	Shares	Aggregate Market Value (millions)
2/16/06	14,375	$0.4
2/9/07	9,020	$0.2
2/6/08	15,540	$0.4

The compensation expense associated with the issuance of shares under the Plan is being accrued over the vesting period and was $0.5 million, $0.4 million and $0.4 million in 2008, 2007 and 2006, respectively. At December 31, 2008, there was approximately $0.8 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over a weighted average of approximately 2.4 years as the shares vest. There were 21,024 and 18,511 non-vested shares under the Plan as of December 31, 2008 and 2007, respectively. The weighted average grant date fair value of these shares was $27.38 and $25.95, respectively. There were no cancellations or forfeitures under the Plan during 2008.

Unitil Corporation Key Employee Stock Option Plan—In the third quarter of 2007, the Company issued and sold 42,437 shares of its common stock, at a final average price of $10.70 per share, in connection with the exercise of stock options under the Unitil Corporation Key Employee Stock Option Plan (KESOP) which expired in 2007. The aggregate intrinsic value of the options exercised was $0.8 million. As of December 31, 2007, there are no options remaining under the KESOP. Net proceeds of $0.5 million were used by the Company to reduce short-term borrowings.

The total compensation expenses recorded by the Company with respect to this plan were $57,000 and $54,000 for the years ended December 31, 2007 and 2006, respectively. There was no compensation expense recorded for the year ended December 31, 2008 with respect to this plan.

Share Option Activity of the "Unitil Corporation Key Employee Stock Option Plan" is presented in the following table:

	2007	2006
Beginning Options Outstanding and Exercisable	**25,000**	25,000
Dividend Equivalents Earned—Prior Years	**15,388**	13,202
Dividend Equivalents Earned—Current Year	**2,049**	2,186
Options Exercised	**(42,437)**	—
Ending Options Outstanding and Exercisable	**—**	40,388
Weighted Average Exercise Price per Share	**$10.70**	$11.25
Range of Option Exercise Price per Share	**$12.11-$18.28**	$12.11-$18.28
Weighted Average Remaining Contractual Life	**n/a**	0.9 years

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's common stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. This plan was terminated on January 16, 2003.

In 2008, the Company issued and sold 3,300 shares of its common stock, at a final average price of $24.51 per share, in connection with the exercise of stock options under the Unitil Corporation 1998 Stock Option Plan. The aggregate intrinsic value of the options exercised was less than $0.1 million. Net proceeds of $0.1 million were used by the Company to reduce short-term borrowings. There was no compensation expense associated with this plan in 2008, 2007 and 2006. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of options will be made under this plan. As of December 31, 2008, there was no aggregate intrinsic value of the options exercisable. As of December 31, 2007, the intrinsic value of the options exercisable was $0.1 million.

	2008		2007		2006	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Beginning Options Outstanding	**107,000**	**$27.13**	107,000	$27.13	107,000	$27.13
Options Granted	**—**	**—**	—	—	—	—
Options Exercised	**(3,300)**	**$24.51**	—	—	—	—
Options Forfeited	**(6,500)**	**$27.99**	—	—	—	—
Ending Options Outstanding	**97,200**	**$27.16**	107,000	$27.13	107,000	$27.13
Options Vested and Exercisable- end of year	**97,200**	**$27.16**	107,000	$27.13	107,000	$27.13

The following summarizes certain data for the options outstanding at December 31, 2008:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
\$20.00-\$24.99	30,700	\$23.38	0.2 years
\$25.00-\$29.99	34,500	\$25.88	2.1 years
\$30.00-\$34.99	32,000	\$32.17	1.1 years
	97,200		

Preferred Stock

Two of Unitil's distribution companies, Unitil Energy and Fitchburg, have \$2.0 million of preferred stock outstanding. At December 31, 2008, Unitil Energy has \$0.2 million of 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and Fitchburg has two series of Redeemable, Cumulative Preferred Stock outstanding, \$0.8 million of 5.125% Series and \$1.0 million of 8.00% Series.

Fitchburg is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, Fitchburg may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2008, 2007 and 2006 related to the annual redemption offer were \$21,200, \$21,700 and \$22,000, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2008 is \$117,000 per year.

Earnings Per Share

The following table reconciles basic and diluted earnings per share.

(Millions except shares and per share data)	2008	2007	2006
Earnings Available to Common Shareholders	**\$ 9.6**	\$ 8.6	\$ 7.9
Weighted Average Common Shares Outstanding—Basic (000's)	**5,830**	5,659	5,597
Plus: Diluted Effect of Incremental Shares (000's)	**—**	13	15
Weighted Average Common Shares Outstanding—Diluted (000's)	**5,830**	5,672	5,612
Earnings per Share—Basic and Diluted	**\$ 1.65**	\$ 1.52	\$ 1.41

Weighted average options to purchase 97,200, 35,000 and 72,500 shares of common stock were outstanding during 2008, 2007 and 2006, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Additionally, 15,985, 2,030 and 24,256 weighted average non-vested restricted shares for 2008, 2007 and 2006, respectively, were not included in the above computation because the effect would have been antidilutive.

Note 5: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowing arrangements. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery, vehicles and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Long-Term Debt Structure and Covenants—The agreements under which the long-term debt of Unitil and its utility subsidiaries, Unitil Energy, Fitchburg, Northern Utilities, and Granite State, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

The long-term debt of Unitil is issued under Unsecured Promissory Notes with negative pledge provisions. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Unitil to issue new long-term debt, the covenants of the existing long-term agreement(s) must be satisfied, including that Unitil have total funded indebtedness less than 70% of total capitalization, and earnings available for interest equal to at least two times the interest charges for funded indebtedness. Each future senior long-term debt issuance of Unitil will rank pari passu with all other senior unsecured long-term debt issuances. The Unitil agreement requires that if Unitil defaults on any other future long-term debt agreement(s), it would constitute a default under its present long-term debt agreement. Furthermore, the default provisions are triggered by the defaults of Unitil Energy and Fitchburg or certain other actions against subsidiary companies in the Unitil System.

Substantially all of the property of Unitil Energy is subject to liens of indenture under which First Mortgage Bonds (FMB) have been issued. In order to issue new FMB, the customary covenants of the existing Unitil Energy Indenture Agreement must be met, including that Unitil Energy have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Unitil Energy agreements further require that if Unitil Energy defaults on any Unitil Energy FMB, it would constitute a default for all Unitil Energy FMB. The Unitil Energy default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

All of the long-term debt of Fitchburg, Northern Utilities and Granite State are issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of long-term debt ranks pari passu with its other senior unsecured long-term debt within that subsidiary. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Fitchburg, Northern Utilities or Granite State to issue new long-term debt, the covenants of the existing long-term agreements of that subsidiary must be satisfied, including that the subsidiary have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Unitil Energy agreements, the Fitchburg, Northern Utilities and Granite State agreements each require that if that subsidiary defaults on any of its own long-term debt agreements, it would constitute a default under all of that subsidiary's long-term debt agreements. Each of the Fitchburg, Northern Utilities and Granite State default provisions are not triggered by the actions or defaults of Unitil or any of its other subsidiaries.

The Unitil, Unitil Energy, Fitchburg, Northern Utilities and Granite State long-term debt instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets. The Granite State notes are guaranteed by Unitil for the payment of principal, interest and other amounts payable. This guarantee will terminate if Granite State is reorganized and merges with and into Northern Utilities.

At December 31, 2008, there were no restrictions on Unitil's Retained Earnings for the payment of common dividends. Unitil Energy, Fitchburg, Northern Utilities and Granite State pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil's common shareholders.

Debt Repayment and Sinking Funds—The total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $363,755, $335,877, and $310,136 in 2008, 2007 and 2006, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2008 is: 2009 – $393,946; 2010 – $426,643; 2011 – $462,055; 2012 – $500,405; and 2013 – $541,938, respectively.

Long-Term Debt Issuances—In connection with the Acquisitions, Northern Utilities issued $80.0 million aggregate principal amount of senior unsecured notes on December 3, 2008, and Granite State issued $10.0 million aggregate principal amount of senior unsecured notes on December 15, 2008., The net proceeds from the Northern Utilities and Granite State notes were used to recapitalize Northern Utilities and Granite State and to ultimately repay a portion of the Company's short-term bank financing facility used to fund the purchase price of the Acquisitions. The notes consist of:

(i) $30.0 million aggregate principal amount of 6.95% senior unsecured notes of Northern Utilities, which are due in 2018;

(ii) $50.0 million aggregate principal amount of 7.72% senior unsecured notes of Northern Utilities, which are due in 2038; and

(iii) $10.0 million aggregate principal amount of 7.15% senior unsecured notes of Granite State, which are due in 2018, along with a guarantee from Unitil for the payment of principal, interest and other amounts payable on the Granite State notes. This guarantee will terminate if Granite State is reorganized and merges with and into Northern Utilities.

On May 2, 2007, Unitil completed the sale of $20 million of Senior Long-Term Notes, through a private placement to institutional investors. The Notes have a term of 15 years maturity and a coupon rate of 6.33%. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries.

On September 26, 2006 Unitil Energy issued and sold $15 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement. The proceeds from this long-term financing were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings.

Fair Value of Long-Term Debt—The fair value of the long-term debt of the Company and its subsidiaries is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the long-term debt of the Company and its subsidiaries at December 31, 2008 is estimated to be in a range of up to approximately $229 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

Details on long-term debt at December 31, 2008 and 2007 are shown below:

Long-Term Debt (millions)	December 31, 2008	December 31, 2007
Unitil Corporation Senior Notes:		
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0
Unitil Energy First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15.0**	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0
Fitchburg Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19.0**	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0
Northern Utilities Senior Notes:		
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	—
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	—
Granite State Senior Notes:		
7.15% Senior Notes, Due December 15, 2018	**10.0**	—
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**4.7**	5.0
Total Long-Term Debt	**249.7**	160.0
Less: Current Portion	**0.4**	0.4
Total Long-Term Debt, Less Current Portion	**$249.3**	$159.6

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)

	2008	2007	2006
Interest Expense			
Long-term Debt	**$12.0**	$11.1	$ 9.5
Short-term Debt	**1.0**	1.1	1.5
Regulatory Liabilities	**0.1**	0.8	0.3
Subtotal Interest Expense	**13.1**	13.0	11.3
Interest Income			
Regulatory Assets	**(2.5)**	(2.9)	(3.1)
AFUDC[1] and Other	**(0.1)**	(0.5)	(0.4)
Subtotal Interest Income	**(2.6)**	(3.4)	(3.5)
Total Interest Expense, net	**$10.5**	$ 9.6	$ 7.8

(1) AFUDC—Allowance for Funds Used During Construction

Credit Arrangements

On November 26, 2008, Unitil entered into a $60 million, 364-day revolving credit agreement with Bank of America, N.A., as administrative agent, and a syndicate of lenders. Borrowings under the revolving credit agreement bear interest at a floating annual rate equal to the daily LIBOR (the London Interbank Offered Rate) reported by the British Banking Association plus the applicable margin. The Company has the option of locking in the daily rate applicable to outstanding loans for one-, two-, three- or six-month interest periods. The applicable margin was initially equal to 1.75%, increased to 3.50% on January 2, 2009, and may be increased over time if the Company does not meet specified conditions with respect to its equity capital. The revolving credit agreement contains customary terms and conditions for credit facilities of this type, including certain financial covenants, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter. The Company had short-term debt outstanding through its revolving credit agreement of approximately $35.0 million and $18.8 million at December 31, 2008 and December 31, 2007, respectively.

The Company financed the Acquisitions and the related costs and expenses in part using borrowings under a bank financing facility. As of December 31, 2008, there was $39.1 million outstanding on this bank financing facility. Amounts outstanding under the bank financing facility accrue interest at either the Eurodollar Rate or the base rate, in each case plus the applicable margin. The Eurodollar Rate is based on an applicable LIBOR as increased by statutory reserve requirements. The base rate is the higher of (i) the prime rate of interest announced publicly by Royal Bank of Canada from time to time and (ii) the Federal Funds Rate plus 0.50%. The applicable margin is a range of interest rates that varies from 2.50% to 5.00% depending on the remaining term of the borrowings. The bank financing facility contains customary terms and conditions, including, without limitation, covenants restricting the Company's ability to (i) pay dividends, (ii) incur indebtedness and liens, (iii) merge or consolidate with another entity or (iv) sell, lease or otherwise dispose of all or substantially all assets.

The weighted average interest rates on all short-term borrowings were 3.8%, 5.6% and 5.5% during 2008, 2007 and 2006, respectively.

On November 1, 2008, Northern Utilities entered into a gas storage management agreement (the Agreement) pursuant to which (i) Northern Utilities released certain pipeline and storage capacity to an asset manager from November 1, 2008 through April 30, 2009 and (ii) the asset manager financed inventories associated with the released storage capacity from Northern Utilities contemporaneously with the closing of the Acquisitions. The Agreement requires Northern Utilities to repurchase quantities of natural gas over the course of the 2008/2009 winter heating season at a specified price and any remaining balance of the gas inventory on April 30, 2009 at the same price initially paid by the asset manager. The Agreement provides for the Company to issue a guarantee of payment of $15 million for the term of the agreement. There is $24.0 million outstanding at December 31, 2008 related to this Agreement.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2008, 2007 and 2006 amounted to $389,000, $433,000 and $410,000 respectively. Fitchburg leases its operations facility in Fitchburg, Massachusetts under an operating lease, with a primary term through January 31, 2013. The lease agreement allows for three additional five-year renewal periods at the option of Fitchburg.

The following is a schedule of future operating lease payment obligations and future minimum lease payments under capital leases as of December 31, 2008:

Year Ending December 31, (000's)	Operating Leases	Capital Leases
2009	$ 929	$ 385
2010	823	345
2011	676	257
2012	549	97
2013	234	41
2014-2018	478	—
Total Payments	$3,689	$1,125

Guarantees

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2008 there are $18.0 million of guarantees outstanding and these guarantees extend through October 31, 2009. Of this amount, $15 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2008, the principal amount outstanding for the 8% Unitil Realty notes was $4.7 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite State notes due 2018. As of December 31, 2008, the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. This guarantee will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Note 6: Energy Supply

Electric Supply:

The transition to retail choice required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive suppliers. Retail choice has been successful for Unitil's largest customers. As of December 2008, 82 or 55% of Unitil's largest New Hampshire customers representing 18% of total New Hampshire electric sales and 27 or 84% of Unitil's largest Massachusetts customers representing 35% of total Massachusetts electric sales are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's local distribution utilities. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential and small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace.

Electric Power Supply Divestiture

Prior to May 1, 2003, Unitil Energy purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, Unitil Energy and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to Unitil Energy ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, Unitil Energy continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. In connection with the implementation of retail choice, Unitil Power and Fitchburg divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts.

Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Natural Gas Supply:

With the purchase of Northern Utilities on December 1, 2008, Unitil now manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and commercial and industrial (C&I) customers have the opportunity to purchase their natural gas supply from third-party vendors, although most of Fitchburg's customers continue to purchase such supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply at regulated rates from Northern Utilities as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its city gate station or underground storage through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern arranges for gas delivery to its city gate station or underground storage through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its city gate station, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Northern Utilities' service territory.

Northern has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Note 7: Commitments and Contingencies

Subsequent Event

On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. As part of this offering, the Company granted the underwriters a 30-day over-allotment option to purchase additional shares. The underwriters exercised the over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increases to Common Equity and Cash from the over-allotment sales were approximately $5.1 million (after payment of the underwriting discount and offering expenses) and were used to repay a portion of the short-term indebtedness used for the Company's acquisitions of Northern Utilities and Granite State. The Company recorded the issuance of the 270,000 shares, the sale proceeds and the increase in Common Equity in January 2009.

Legal Proceedings

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. The complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. As of this date the complaint has not been served on Fitchburg. The Company believes this complaint is without merit, and will defend itself vigorously.

Regulatory Matters

Overview (Unitil Energy, Fitchburg, and Northern Utilities)—Unitil's distribution utilities deliver electricity and/or natural gas to all customers in the Company's service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next two to four years, is $81.9 million as of December 31, 2008 including $22.1 million in Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Unitil Energy—Unitil Energy provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current electric distribution base rates were approved by the NHPUC in 2006 under a Settlement Agreement with the NHPUC. As the provider of last resort, Unitil Energy also provides its customers with electric power through Default Service at rates which reflect Unitil Energy's costs for wholesale supply with no profit or markup. Unitil Energy procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts procured on a semi-annual basis. Unitil Energy recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of December 31, 2008, approximately 80 percent of Unitil Energy's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large C&I customers. Most residential and small commercial customers continue to purchase their electric supply through the distribution utility.

Under its 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for Unitil Energy for stranded cost recovery, including certain charges that remain subject to annual or periodic reconciliation or future review. Unitil Energy had recorded on its balance sheets $18.9 and $30.7 million as Energy Supply Contract Obligations, respectively, on the Company's Consolidated Balance Sheet as of December 31, 2008 and 2007, respectively, associated with these long-term purchase power stranded costs, which are included in Unitil's consolidated financial statements. These Energy Supply Contract Obligations are expected to be recovered principally over a period of approximately two years. Unitil Energy does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 14, 2008, Unitil Energy made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective May 1, 2008, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. The filing was approved on April 23, 2008. On July 9, 2008, Unitil Energy proposed an increase to its External Delivery Charge, effective September 1, 2008, reflecting higher transmission costs. The filing was approved on August 29, 2008.

On January 22, 2008, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. The NHPUC determined that it is appropriate to implement some form of time-based metering standards and ordered that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes are to be determined in separate proceedings initiated by the NHPUC. The NHPUC also found that additional review of the energy standards for net metering, fuel diversity and fossil fuel generation efficiency as proposed in the Energy Policy Act of 2005 is not required due to action of the New Hampshire legislature and the NHPUC in adopting comparable standards.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On January 16, 2009, the NHPUC issued its decision in this matter, concluding that such rate mechanisms should only be implemented on a company-by-company basis in the context of an examination of company specific costs and revenues, service territory, customer mix and rate base investment.

Unitil Energy—Other: In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation.

Fitchburg—Electric Operations—Fitchburg provides electric distribution service to customers under unbundled distribution rates approved by the MDPU. Its current electric distribution base rates were approved by the MDPU in 2008. Fitchburg, as the provider of last resort, also provides its customers with electric power through Basic Service at rates which reflect Fitchburg's costs for wholesale supply with no profit or markup. Prices for Basic Service are set periodically based on market solicitations as approved by the MDPU. As of December 31, 2008, approximately 59 percent of Fitchburg's electric load was served by Basic Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large commercial and industrial (C&I) customers.

As a result of the restructuring and the divestiture of Fitchburg's owned generation assets and buyout of Fitchburg's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Energy Supply Contract Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of generation plant owned by Fitchburg. Fitchburg earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of Fitchburg's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $29.1 million at December 31, 2008, and $32.1 million at December 31, 2007, including $4.1 million and $3.9 million, respectively, included in Accrued Revenue, and is expected to be recovered in Fitchburg's rates over the next four years. In addition, Fitchburg had recorded on its balance sheet $33.8 million at December 31, 2008, and $42.0 million at December 31, 2007, as Energy Supply Contract Obligations associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

The Company received a final order from the MDPU on February 29, 2008 approving an electric rate increase of $2.1 million, effective March 1, 2008.

Pursuant to its approved electric restructuring plan, toward the end of each year Fitchburg submits its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service. Fitchburg's 2007 filing, submitted on December 3, 2007, was approved by the MDPU on August 19, 2008. On November 26, 2008, Fitchburg submitted its annual reconciliation filing for 2008. The rates were approved effective January 1, 2009, subject to further investigation. This matter remains pending.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Unitil was able to restore power to one-third of its Massachusetts customers within three days, and 80 percent of its customers by day seven, and the final Massachusetts customers, including those with individual service problems, were restored by day 13, December 24, 2008. On January 7, 2009, the MDPU opened an investigation into the Preparation and Response of the Massachusetts electric distribution companies to the December 12, 2008 Winter Storm. Each electric distribution company has been ordered to file a report detailing its response to the storm and outages, and its service restoration efforts with the MDPU by February 23, 2009. Public hearings have been held in each of the electric distribution utilities' service areas in Massachusetts. Based on its preliminary assessment, the Company has accrued and deferred approximately $10 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. This matter remains pending.

Fitchburg—Gas Operations—Fitchburg provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current distribution base rates were approved by the MDPU in 2007. Fitchburg's customers may purchase natural gas supplies from third-party vendors or purchase their natural gas from Fitchburg as the provider of last resort. Fitchburg collects its natural gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

Fitchburg—Other—On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, including company specific rate cases. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012. Each distribution company was required to notify the MDPU of when the company expects to file a rate case to implement decoupling. Fitchburg notified the MDPU that it will be prepared to file rate cases for each of its divisions by the third quarter of 2009, based upon a calendar 2008 test year, along with a comprehensive decoupling proposal and associated base rate adjustment mechanism. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "*The Green Communities Act*" (the GC Act), an energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act includes provisions that:

- Require electric and natural gas distribution companies to file three-year energy efficiency investment plans designed to implement all available cost-effective energy efficiency and demand reduction resources; the plans are to include fully reconciling funding mechanisms;

- Require utility distribution companies to undertake various Green programs, including the solicitation of bids for long-term renewable energy procurement contracts for which utilities would be allowed remuneration on certain contract commitments;
- Establishes expanded authority for the MDPU to investigate mergers involving holding companies of public utilities;
- Increase the Renewable Portfolio Standard by 1% annually, requiring that by the year 2020 utilities and other electricity suppliers obtain 15% of the power they sell from renewable resources;
- Authorize electric distribution companies to construct, own, and operate up to 50 megawatts of solar generating capacity; and
- Modify the service quality performance penalty provision.

The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs.

Northern Utilities Acquisition—Northern Utilities is a New Hampshire corporation and a public utility under both New Hampshire and Maine law. Northern Utilities provides natural gas distribution services to a total of 52,000 customers in 44 New Hampshire and southern Maine communities. On December 1, 2008 Unitil completed the purchase of Northern Utilities from Bay State Gas Company (a subsidiary of NiSource, Inc.) and Granite State from NiSource Inc. The purchase agreement between Bay State, NiSource and Unitil was announced on February 19, 2008. Joint petitions on behalf of Unitil and Northern Utilities requesting approval of the purchase of Northern Utilities by Unitil were filed with the NHPUC and the MPUC on March 31, 2008. State regulatory approvals of Unitil's purchase of Granite State were not required. In August 2008, unopposed settlement agreements resolving all outstanding issues and recommending approval of the acquisition were filed with the NHPUC and MPUC on behalf of Unitil, Northern Utilities and the active parties to the respective New Hampshire and Maine proceedings. The NHPUC approved the transaction on October 10, 2008. The MPUC issued an order approving the transaction with conditions on October 22, 2008, which it modified on November 5, 2008.

Although separately negotiated and filed with the MPUC and the NHPUC, the settlement agreements reflect several common topics (including regulatory authorizations, matters affecting rates, customer service provisions, service quality, gas safety and reliability, agreements regarding Granite State and reporting requirements) as follows:

The settlement agreements include the following authorizations and approvals:

- approval of Unitil's acquisition of Northern Utilities;
- approval of the amended Unitil Service Agreement adding Northern Utilities as a party;
- approval of the amended Unitil Cash Pooling Agreement adding Northern Utilities as a party; and
- approval of Northern Utilities' accounting deferral and 10-year amortization of transaction costs and transition costs resulting from the Company's acquisition of Northern Utilities and the Company's agreement not to seek recovery of these costs, or the transaction or transition costs of any other utility subsidiary, in rates.

The settlement agreements include the following commitments related to rates:

- agreement that synergy savings resulting from our acquisition of Northern Utilities will be retained by the Company until the next base rate change and then will flow to customers;
- agreement not to request a base rate change for Northern Utilities before November 1, 2010 unless (i) Northern Utilities' projected annual revenues are more than 8% below the level of total 2007 distribution revenues or (ii) the MPUC or NHPUC, as applicable, approves a plan to subject Granite State's rates to state regulation;
- agreement to allow Northern Utilities to recover prudently incurred integration costs for capitalized expenditures to build or upgrade systems or facilities required to independently operate Northern Utilities;

- agreement not to seek recovery in Northern Utilities' rates of any acquisition premium resulting from Unitil's acquisition of Northern Utilities and that any acquisition adjustment (positive or negative) shall be accounted for below the line for ratemaking purposes over a 10-year period;
- agreement to hold Northern Utilities' customers harmless for the elimination of historical accumulated deferred income tax (ADIT) liabilities resulting from its Internal Revenue Service Section 338(h)(10) election;
- agreement to use an imputed weighted cost of debt for ratemaking purposes until Northern Utilities' existing debt instruments would have matured; and
- agreement not to change Northern Utilities' existing depreciation rates for its Maine division until approved in the next general rate case.

The settlement agreements also contain the following commitments related to customers:

- agreement to implement a Low Income Program for Northern Utilities' Maine division, to provide additional customer payment options (including credit or debit cards and by internet and telephone) for Maine customers and to continue low income programs in Northern Utilities' New Hampshire division;
- agreement to review with the parties to the settlements communications that we develop to inform Northern Utilities' customers about our acquisition of Northern Utilities and to keep them apprised of the transition; and
- with respect to Maine, agreement to conduct a study of alternatives for the sale, lease, or use of the unused Portland manufactured gas site property that would best serve ratepayers' interests.

The settlement agreements contain the following commitments related to service quality, gas safety and reliability:

- agreement to improve and adhere to Northern Utilities' existing service quality plans in each jurisdiction; and
- agreement to provide notifications and safety reports based on several service quality and gas safety metrics, as well as implementing gas operations programs and practices.

The settlement agreements contain the following commitments related to Granite State:

- agreement to work collaboratively with the parties to the settlements to design and to conduct a comprehensive study of the issues and costs for modification of the physical, operational, regulatory, and corporate structure necessary for state regulation of Granite State and to provide a report within one year of the closing; and
- authorization for Northern Utilities to execute a firm service contract with Granite State for 100,000 Dekatherms (Dth) of capacity at Granite State's current recourse rate of $1.6666/ Dth for the period November 1, 2008 through October 31, 2010.

The settlement agreements contain the following commitments regarding affiliate books and records and transaction reporting:

- agreement to provide timely access to the books and records of any of Northern Utilities' affiliates at the discretion of the MPUC or the NHPUC, as applicable;
- agreement to file reports on our transition progress, business integration, costs, the Transition Services Agreement and costs while our acquisition of Northern Utilities was pending; and
- agreement to notify the MPUC and the NHPUC of any substantial changes in the financing terms.

In Massachusetts, the GC Act expanded the authority of the MDPU to review holding company mergers and sales of subsidiaries to determine how such transactions would affect the holding companies' Massachusetts' utility operating companies and their ratepayers. Unitil and Bay State filed a joint Petition with the MDPU on August 13 seeking an advisory determination that the recent statutory amendment was inapplicable to the proposed sale, or, alternatively, sought approval of the proposed sale. The MDPU declined to issue the advisory ruling, and determined that it had the requisite authority to review the transaction. After investigation and hearing, the MDPU issued its approval of the transaction on November 18, 2008.

Northern Utilities—Notices of Probable Violation—Beginning in October 2007, the MPUC initiated formal investigations into a number of Notices of Probable Violation (NOPVs) alleging that Northern Utilities had violated various provisions of the federal pipeline safety regulations, as adopted by the MPUC. Northern Utilities, the MPUC Staff and Unitil filed a comprehensive settlement (Settlement), which was approved by the MPUC on November 21, 2008, resolving these matters. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for certain safety related improvements for which no rate recovery will be allowed and obligations to be undertaken for Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at December 31, 2008 was $3.1 million.

Northern Utilities—New Hampshire 2007/2008 Winter Cost of Gas—On October 31, 2007, the NHPUC issued Order No. 24,798 concerning the 2007/2008 winter cost of gas proceeding for Northern Utilities' New Hampshire division. In that order, the NHPUC noted that Northern Utilities had identified an unusually high level of lost and unaccounted for gas (UAFG), and ordered Northern Utilities to file a detailed report concerning its investigation of this matter. Through its investigation, Northern Utilities determined that the unaccounted for gas affected both its New Hampshire and Maine divisions, and that the cause appeared to be incorrect metering at the Maritimes & Northeast (M&NE) / Portland Natural Gas Transmission System's (PNGTS) Newington Gate Station caused by an erroneous meter module change. The metering equipment was operated and maintained by a third party, Spectra Energy, the parent company of M&NE. PNGTS and M&NE share joint ownership of the section of the pipeline connected to Granite State at the Newington Gate Station. The error caused Granite State to be billed for 758,702 Dth of natural gas, with Granite State then billing Northern Utilities for an equivalent amount, although the volumes of gas were not actually consumed. The meter error was corrected and Northern Utilities, Granite State, Spectra Energy and PNGTS reached an agreement whereby PNGTS will provide to Northern Utilities, through Granite State, gas volumes equal to the misread amounts to correct for the error, over a period of approximately 18 months. Both the NHPUC and the MPUC have approved this arrangement, as well as Northern Utilities' methodology for allocating the gas received to its Maine and New Hampshire divisions based upon the actual gas use over the period the meters were misread. As of December 31, 2008, Northern Utilities has recorded approximately $4.0 million reflecting the anticipated liability of the future refund amount based on current market prices with an offsetting receivable from Granite State.

Northern Utilities—Maine Capacity Costs—In its October 28, 2008 approval of Northern Utilities' Maine Division's Cost of Gas Factor for the 2008-2009 Winter Period, the MPUC approved recovery of an additional $0.5 million of annual demand costs that had been inadvertently omitted from Northern Utilities' reconciliation of the 2008-2009 Winter Period rates, although analogous costs had been included in its calculation of 2007-2008 Winter Period rates. The MPUC determined that recovery of these Local Production Capacity Costs was consistent with previous MPUC orders.

Northern Utilities also reported that, upon investigation, these annual demand costs, though approved, were incorrectly excluded from its reconciliation for five previous annual periods. The total impact for the five years is $2.4 million. On November 7, 2008, Northern Utilities filed a request with the MPUC seeking an accounting order allowing it to defer and amortize for recovery these unrecovered gas costs over a three year period. This matter remains pending.

Granite State—Granite State's interstate natural gas transmission pipeline system is regulated by the FERC under the Natural Gas Act, the Natural Gas Policy Act of 1978, and the Energy Policy Act of 2005. Granite State's system operates under a tariff approved by the FERC that establishes rates, cost recovery mechanisms, and terms and conditions of service for its customers. Additionally, interstate pipeline companies such as Granite State are subject to regulation by the U.S. Department of Transportation pursuant to the Natural Gas Pipeline Safety Act, which authorizes safety requirements in the design, construction, operations and maintenance of interstate natural gas transmission facilities. Granite State's last base rate case was resolved through stipulation and approved by the FERC on October 20, 1997. Granite State's Phase II rates, consistent with this stipulation became effective May 1, 1998.

FERC—Wholesale Power Markets—Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are market participants in the regional bulk power system administered by ISO-NE, the RTO in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is coordinated on a regional basis. The ISO-NE Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's utility operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the NHPUC and MDPU.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2008, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Fitchburg is in the process of developing long-range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2008 and 2007 in Environmental Obligations is $11.1 million and $12.0 million, respectively, related to estimated future clean up costs for permanent remediation of the Sawyer Passway site. A corresponding Regulatory Asset was recorded to reflect that the recovery of this environmental remediation cost is probable through the regulatory process. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

Northern Utilities Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800s through the mid 1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Include in the Company's Consolidated Balance Sheet at December 31, 2008 are current and non-current accrued liabilities totaling $1.6 million associated with Northern Utilities environmental remediation obligations for these former MGP sites. A corresponding Regulatory Asset was recorded to reflect that the recovery of these environmental remediation cost is probable through the regulatory process.

The Company's ultimate liability for future environmental remediation costs, including MGP site costs, may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

The following table shows the balances and activity in the Company's liability for Environmental Obligations for 2008. The liability for Environmental Obligations was initially recognized on the Company's Consolidated Balance Sheet at December 31, 2006.

ENVIRONMENTAL OBLIGATIONS

	December 31,	
(Millions)	**2008**	**2007**
Balance at Beginning of Period	**$12.0**	$12.0
Liabilities Assumed	**1.6**	—
Provision	**—**	—
Payments / Reductions	**0.9**	—
Total Environmental Obligations—Balance at End of Period	**12.7**	12.0
Less: Current Portion (1)	**0.4**	—
Environmental Obligations—noncurrent—Balance at End of Period	**$12.3**	$12.0

(1) Reflects amounts included in Other Current Liabilities on the Company's Consolidated Balance Sheets.

Note 8: Bad Debts

Unitil's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. In 2006, 2007 and 2008, the Company recorded provisions for the energy commodity portion of bad debts of $1.7 million, $1.5 million and $2.1 million, respectively. These provisions were recognized in Purchased Electricity and Purchased Gas expense as the associated electric and gas utility revenues were billed. Purchased Electricity and Purchased Gas costs are recovered from customers through periodic rate reconciling mechanisms. Prior to 2006, the commodity portion of bad debt expense was recognized in Purchased Electricity and Purchased Gas expense when the accounts were actually written off from accounts receivable.

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2006 – 2008.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	(a) Other	Provision	Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2008						
Electric	**$1,005,548**	**$ —**	**$2,235,784**	**$239,752**	**$2,334,627**	**$1,146,457**
Gas	**225,301**	**1,361,889**	**1,430,914**	**164,821**	**1,401,236**	**1,781,689**
Other	**35,541**	**—**	**49,928**	**2,364**	**1,945**	**85,888**
	$1,266,390	**$1,361,889**	**$3,716,626**	**$406,937**	**$3,737,808**	**$3,014,034**
Year Ended December 31, 2007						
Electric	$1,264,102	$ —	$1,434,356	$147,497	$1,840,407	$1,005,548
Gas	438,159	—	971,958	113,924	1,298,740	225,301
Other	34,526	—	34,659	—	33,644	35,541
	$1,736,787	$ —	$2,440,973	$261,421	$3,172,791	$1,266,390
Year Ended December 31, 2006						
Electric	$ 342,791	$ —	$1,963,222	$136,399	$1,178,310	$1,264,102
Gas	110,031	—	1,325,650	134,802	1,132,324	438,159
Other	16,926	—	29,313	1,780	13,493	34,526
	$ 469,748	$ —	$3,318,185	$272,981	$2,324,127	$1,736,787

(a) Includes Allowance for Doubtful Accounts of Northern Utilities and Granite State, which were acquired on December 1, 2008.

Note 9: Income Taxes

Federal Income Taxes were provided for the following items for the years ended December 31, 2008, 2007 and 2006, respectively:

	2008	2007	2006
Current Federal Tax Provision (Benefit) (000's):			
Operating Income	**$(2,914)**	$4,522	$3,448
Total Current Federal Tax Provision (Benefit)	**(2,914)**	4,522	3,448
Deferred Federal Tax Provision (Benefit) (000's)			
Depreciation and Utility Plant	**5,159**	(444)	(656)
Regulatory Assets and Liabilities	**1,534**	(400)	790
Other, net	**121**	60	184
Total Deferred Federal Tax Provision (Benefit)	**6,814**	(784)	318
Total Federal Tax Provision	**$ 3,900**	$3,738	$3,766

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2008, 2007 and 2006 are shown in the table below. In addition to the provisions for federal and state income taxes, the Company recorded provisions of $165,000, $203,000 and $211,000 in 2008, 2007 and 2006, respectively for state Business Enterprise taxes, which are included in Local Property and Other Taxes on the consolidated statements of earnings.

Federal and State Tax Provision (Benefit) (000's)	2008	2007	2006
Federal			
Current	**$(2,914)**	$4,522	$3,448
Deferred	**6,814**	(784)	318
Total Federal Tax Provision	**3,900**	3,738	3,766
State			
Current	**(42)**	896	337
Deferred	**592**	(138)	163
Total State Tax Provision	**550**	758	500
Total Provision for Federal and State Income Taxes	**$ 4,450**	$4,496	$4,266

The differences between the Company's provisions for Income Taxes, including the provision for Business Enterprise taxes, and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2008	2007	2006
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**5**	5	5
Utility Plant Differences	**(6)**	(4)	(4)
Tax Credits and Other, Net	**(1)**	—	1
Effective Income Tax Rate	**32%**	35%	36%

Temporary differences, including the effect of deferred tax accounting on the assets and liabilities of Northern Utilities and Granite State acquired on December 1, 2008 (see Note 3 above), which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	2008	2007
Depreciation and Utility Plant	**$ 26,719**	$ 27,356
Regulatory Assets / Liabilities & Mechanisms	**30,071**	23,239
Retirement Benefit Obligations	**(23,029)**	(15,585)
Other	**(2,677)**	(1,627)
Total Deferred Income Tax Liabilities	**$ 31,084**	$ 33,383

The Company evaluated its tax positions at December 31, 2008 in accordance with FIN 48, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2005; December 31, 2006; and December 31, 2007. Income tax filings for the year ended December 31, 2008 are due March 15, 2009 but likely will be extended until September 15, 2009. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Note 10: Retirement Benefit Plans

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan)—The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.
- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan)—The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.
- The Unitil Corporation Supplemental Executive Retirement Plan (SERP)—The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

Effective with the acquisitions of Northern Utilities and Granite State, the Company assumed the assets and obligations of the Northern Utilities and Granite State pension plans with respect to active union employees. All other active employees of Northern Utilities and Granite State effectively became members of the Company's Pension Plan as of the acquisitions closing date.

Certain employees of Northern Utilities qualified for participation in the Company's PBOP Plan effective with the acquisition closing date.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan costs for years ended December 31:	**2008**	**2007**	**2006**
Discount Rate	**6.00%**	5.50%	5.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2016	2016
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 675**	$ 690	$ 683
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$ (531)**	$ (539)	$ (530)
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**6.25%**	6.00%	5.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	8.50%	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2017	2016
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 6,084**	$ 6,282	$ 6,381
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$(4,890)**	$(5,030)	$(5,091)

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2008, 2007 and 2006, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost (NPBC). The Rate of Compensation Increase assumption used for 2008, 2007 and 2006 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The Expected Long-Term Rate of Return on plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on plan assets is based on target investment allocation of 60% in common stock equities and 40% in fixed income securities. The actual investment allocations are shown in the table below.

	Target Allocation 2009	Actual Allocation at December 31, 2008	2007	2006
Equity Securities	58%	**54%**	57%	61%
Debt Securities	32%	**35%**	43%	39%
Other	10%	**11%**	0%	0%
Total		**100%**	100%	100%

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2008. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan			PBOP Plan			SERP		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Service Cost	**$ 1,979**	$ 1,968	$ 1,800	**$ 1,447**	$ 1,431	$ 1,283	**$150**	$163	$148
Interest Cost	**3,800**	3,336	3,153	**2,212**	2,057	2,028	**126**	118	103
Expected Return on Plan Assets	**(4,390)**	(4,195)	(3,775)	**(325)**	(245)	(194)	**—**	—	—
Prior Service Cost Amortization	**119**	106	107	**1,390**	1,360	1,360	**(1)**	(2)	(2)
Transition Obligation Amortization	**—**	—	—	**21**	21	21	**—**	—	17
Actuarial Loss Amortization	**1,274**	1,345	1,324	**—**	70	160	**24**	44	39
Sub-total	**2,782**	2,560	2,609	**4,745**	4,694	4,658	**299**	323	305
Amounts Capitalized and Deferred	**(893)**	(873)	(1,014)	**(1,872)**	(2,033)	(2,217)	**—**	—	—
NPBC Recognized	**$ 1,889**	$ 1,687	$ 1,595	**$ 2,873**	$ 2,661	$ 2,441	**$299**	$323	$305

The estimated amortizations related to Actuarial Loss and Prior Service Cost included in the Company's Retirement plan costs over the next fiscal year is $1.9 million, $1.7 million and $0.1 million for the Pension, PBOP and SERP plans, respectively.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2008, 2007 and 2006 before capitalization and deferral was $2.8 million, $2.6 million and $2.6 million, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2008, 2007 and 2006 would have been $2.9 million, $2.5 million and $2.8 million respectively.

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan		PBOP Plan		SERP	
Change in Plan Assets:	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Plan Assets at Beginning of Year	**$ 52,162**	$ 49,527	**$ 4,144**	$ 3,052	**$ —**	$ —
Actual Return on Plan Assets	**(15,542)**	2,480	**(784)**	89	**—**	—
Employer Contributions	**2,800**	2,800	**2,700**	2,500	**59**	72
Estimated Acquired Plan Assets	**2,500**	—	**—**	—	**—**	—
Benefits Paid	**(2,796)**	(2,645)	**(1,699)**	(1,497)	**(59)**	(72)
Plan Assets at End of Year	**$ 39,124**	$ 52,162	**$ 4,361**	$ 4,144	**$ —**	$ —
Change in PBO:						
PBO at Beginning of Year	**$ 64,429**	$ 62,027	**$ 37,983**	$ 38,107	**$ 2,144**	$ 2,179
Service Cost	**1,979**	1,968	**1,447**	1,431	**150**	163
Interest Cost	**3,800**	3,336	**2,212**	2,057	**126**	118
Estimated Acquired Obligations	**4,442**	—	**2,610**	—	**—**	—
Benefits Paid	**(2,796)**	(2,645)	**(1,699)**	(1,497)	**(59)**	(72)
Actuarial (Gain) or Loss	**(1,468)**	(257)	**(4,898)**	(2,115)	**569**	(244)
PBO at End of Year	**$ 70,386**	$ 64,429	**$ 37,655**	$ 37,983	**$ 2,930**	$ 2,144
Funded Status: Assets vs PBO	**$(31,262)**	$(12,267)	**$(33,294)**	$(33,839)	**$(2,930)**	$(2,144)

In September 2006, the FASB issued SFAS No. 158 which requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets of $45.5 million and $35.1 million at December 31, 2008 and 2007, respectively, to recognize the future collection of these plan obligations in electric and gas rates.

In accordance with SFAS No. 132 "Employers Disclosures about Pensions and Other Postretirement Benefits," the Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $61.1 million and $55.1 million as of December 31, 2008 and 2007, respectively. The ABO for the SERP was $0.5 million and $0.6 million as of December 31, 2008 and 2007, respectively. For the PBOP Plan, the ABO and PBO are the same.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in

2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 - 2010 plan years. This did not affect the Company's Pension Plan in 2008 as its Pension Plan was 99% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2008 and met the exemption from the shortfall amortization. The Company expects to contribute approximately $4.0 million to fund its Pension Plan in 2009.

The following table represents employer contributions and benefit payments ($000's). There were no participant contributions.

	Pension Plan			PBOP Plan			SERP		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**
Employer Contributions	**$2,800**	$2,800	$2,510	**$2,700**	$2,500	$2,210	**$59**	$72	$72
Benefit Payments	**$2,796**	$2,645	$2,476	**$1,699**	$1,497	$1,540	**$59**	$72	$72

The following table represents estimated future benefit payments ($000's).

	Estimated Future Benefit Payments		
	Pension	**PBOP**	**SERP**
2009	$ 3,356	$ 1,360	$ 52
2010	3,557	1,554	51
2011	3,718	1,709	50
2012	3,834	1,844	49
2013	4,166	1,983	315
2014 - 2018	$23,669	$11,555	$1,551

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. The Company matches contributions, with a maximum matching contribution of 3% of current compensation. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company common stock fund. Participants are 100% vested in contributions made on their behalf, once they have completed three years of service. The Company's share of contributions to the 401(k) Plan was $542,000, $533,000 and $528,000 for the years ended December 31, 2008, 2007, and 2006, respectively.

Note 11: Segment Information

Unitil reports four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capitol regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine.

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transmission services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty, Unitil Service and the holding company are included in the “Other” column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company’s corporate headquarters. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries’ use. Unitil Resources and Usource are included in the Non-Regulated column below.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes and preferred stock dividends. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on cost allocation factors included in rate applications approved by the NHPUC, MDPU, and MPUC. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2008, 2007 and 2006 (Millions):

Year Ended December 31, 2008	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$227.5**	**$ 56.9**	**$ —**	**$ 3.8**	**$288.2**
Interest Income	**2.2**	**0.1**	**0.3**	**—**	**2.6**
Interest Expense	**8.7**	**2.3**	**2.1**	**—**	**13.1**
Depreciation & Amortization Expense	**13.1**	**5.2**	**0.8**	**—**	**19.1**
Income Tax Expense (Benefit)	**1.9**	**2.6**	**(0.3)**	**0.2**	**4.4**
Segment Profit (Loss)	**5.2**	**4.3**	**(0.2)**	**0.3**	**9.6**
Segment Assets	**351.9**	**362.3**	**20.0**	**1.0**	**735.2**
Capital Expenditures	**19.7**	**7.6**	**1.0**	**—**	**28.3**
Year Ended December 31, 2007					
Revenues	$225.0	$ 34.2	$ —	$ 3.7	$262.9
Interest Income	2.8	0.1	0.5	—	3.4
Interest Expense	9.6	2.1	1.3	—	13.0
Depreciation & Amortization Expense	12.6	3.8	1.3	0.1	17.8
Income Tax Expense (Benefit)	3.8	0.4	0.1	0.2	4.5
Segment Profit (Loss)	7.3	1.0	—	0.3	8.6
Segment Assets	334.1	111.9	27.8	0.8	474.6
Capital Expenditures	26.2	6.1	0.2	—	32.5
Year Ended December 31, 2006					
Revenues	$225.2	$ 33.3	$ —	$ 2.4	$260.9
Interest Income	3.0	0.1	0.4	—	3.5
Interest Expense	9.5	1.1	0.6	0.1	11.3
Depreciation & Amortization Expense	11.2	3.5	1.3	0.1	16.1
Income Tax Expense (Benefit)	4.2	0.1	0.1	(0.1)	4.3
Segment Profit (Loss)	7.0	0.5	0.6	(0.2)	7.9
Segment Assets	346.7	113.1	22.7	0.9	483.4
Capital Expenditures	26.3	7.2	0.1	—	33.6

Note 12: Quarterly Financial Information (unaudited; Millions, except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2008	2007	2008	2007	2008	2007	2008	2007
Total Operating Revenues	**$ 71.9**	$ 77.8	**$ 59.4**	$ 59.0	**$ 69.1**	$ 61.8	**$ 87.8**	$ 64.3
Operating Income	**$ 6.0**	$ 4.7	**$ 4.2**	$ 4.3	**$ 3.9**	$ 3.9	**$ 6.4**	$ 5.6
Net Income Applicable to Common	**$ 3.3**	$ 2.6	**$ 1.6**	$ 1.7	**$ 1.5**	$ 1.6	**$ 3.2**	$ 2.7
	Per Share Data:							
Earnings Per Common Share	**$ 0.57**	$ 0.46	**$ 0.28**	$ 0.30	**$ 0.27**	$ 0.28	**$ 0.53**	$ 0.48
Dividends Paid Per Common Share	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345

Note 13: Unaudited Pro Forma Financial Data Related To Acquisitions

On December 1, 2008, the Company acquired Northern Utilities and Granite State, as discussed in Note 3. Had the results of operations for Northern Utilities and Granite State been combined with the Company as of the beginning of 2007, the Company's pro forma results for 2008 and 2007 would have been as follows:

	Year ended December 31,	
(Millions, except per share amounts) (Unaudited)	2008	2007
Revenues	**$395.5**	$396.2
Earnings Applicable to Common Shareholders	**$ 6.9**	$ 10.2
Earnings per Share		
Basic	**$ 0.88**	$ 1.33
Diluted	**$ 0.88**	$ 1.33

The Unaudited Pro Forma Financial Data include non-recurring charges to operating expenses of $1.7 million, after tax, related to compliance violation penalties incurred by Northern Utilities in 2007 and $2.5 million, after tax, related to compliance violation penalties incurred by Northern Utilities in 2008.

The Unaudited Pro Forma Financial Data are presented for illustrative purposes only and do not indicate the financial results of the combined companies had the companies actually been combined and had the impact of possible revenue enhancements and expense efficiencies, among other factors, been considered, and is not intended to be a projection of future results.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of December 31, 2008. Based upon this evaluation, the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded as of December 31, 2008 that the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) are effective.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). In addition, management is required to report their assessment, including their evaluation criteria, on the design and operating effectiveness of the Company's internal control over financial reporting in this Form 10-K.

The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The Company's internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles. The Company's internal control over financial reporting includes policies and procedures which provide reasonable assurances that transactions are properly initiated, authorized, recorded, reported and disclosed, and provide reasonable assurances regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

During 2008, management conducted an assessment of the Company's internal control over financial reporting reflected in the financial statements, based upon criteria established in the "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Our assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Northern Utilities, Inc. and Granite State Gas Transmission, Inc., businesses that we acquired on December 1, 2008 and which are included in the Company's 2008 consolidated financial statements. Total assets for Northern Utilities and Granite State were $250.8 million and $22.9 million, respectively, as of December 31, 2008. Total revenues for Northern Utilities and Granite State were $21.8 million and $0.4 million, respectively, for the year ended December 31, 2008, reflecting the period of December 1, 2008 through December 31, 2008.

Based on management's assessment, which included a comprehensive review of the design and operating effectiveness of the Company's internal control over financial reporting, management believes the Company's internal control over financial reporting is designed and operating effectively as of December 31, 2008.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Vitale, Caturano and Company, an independent registered public accounting firm. Their report appears in Item 8.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

None

PART III

Item 10. Directors and Executive Officers of the Registrant

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 16, 2009.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Compensation Discussion and Analysis" and "Compensation of Named Executive Officers" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 16, 2009.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the "Beneficial Ownership" and "As to the Election of Directors" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 16, 2009, as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions

None

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 16, 2009.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2008 and 2007
- Consolidated Statements of Earnings for the years ended December 31, 2008, 2007, and 2006
- Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007, and 2006
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2008, 2007, and 2006
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	Articles of Amendment to the Articles of Incorporation Filed on September 23, 2008.	Exhibit 3.3 to Form S-3/A dated November 25, 2008
3.4	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.5	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.6	Articles of Exchange of CECo, E&H, and the Company - Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.7	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (Fitchburg) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.8	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989

Exhibit Number	Description of Exhibit	Reference*
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002
4.2	Fitchburg Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.3	Fitchburg Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.4	Fitchburg Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.5	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.6	Fitchburg Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.7	Fitchburg Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
4.8	Thirteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of September 26, 2006.	**
4.9	Unitil Corporation Note Purchase Agreement, dated as of May 2, 2007, for the 6.33% Senior Notes due May 1, 2022.	**
4.10	Northern Utilities Note Purchase Agreement, dated as of December 3, 2008, for the 6.95% Senior Notes, Series A due December 3, 2018 and the 7.72% Senior Notes, Series B due December 3, 2038.	Exhibit 4.1 to Form 8-K dated December 3, 2008
4.11	Granite State Note Purchase Agreement, dated as of December 15, 2008, for the 7.15% Senior Notes due December 15, 2018	Exhibit 99.1 to Form 8-K dated December 15, 2008
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 8-K dated June 19, 2008
10.5***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.3 to Form 8-K dated June 19, 2008
10.6***	Amended and Restated Unitil Corporation Supplemental Executive Retirement Plan effective as of December 31, 2007.	Exhibit 10.4 to Form 8-K dated June 19, 2008

Exhibit Number	Description of Exhibit	Reference*
10.7***	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.8***	Amended and Restated Unitil Corporation Management Incentive Plan effective as of June 19, 2008 as further amended on December 1, 2008.	Filed herewith
10.9	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.10***	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.11	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.12	Unitil Corporation Tax Deferred Savings and Investment Plan – Trust Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2004
10.13***	Amended and Restated Employment Agreement effective as of June 30, 2008 by and between Unitil Corporation and Robert G. Schoenberger.	Exhibit 10.1 to Form 8-K dated June 19, 2008
10.14	Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated November 26, 2008
10.15	Amendment Agreement dated as of January 2, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated January 2, 2009
10.16	Credit Agreement between Unitil Corporation and Royal Bank of Canada dated December 1, 2008	Exhibit 10.2 to Form 8-K dated November 26, 2008
10.17	Transition Services Agreement between Unitil Corporation and NiSource, Inc. dated December 1, 2008	Exhibit 10.3 to Form 8-K dated November 26, 2008
10.18	Parent Guaranty of Unitil Corporation for the Granite State 7.15% Senior Notes due December 15, 2018	Exhibit 10.1 to Form 8-K dated December 15, 2008
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith

Exhibit Number	Description of Exhibit	Reference*
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** In accordance with Item 601(b)(4)(iii)(A) of Federal Securities Regulation S-K, the instrument defining the debt of the Registrant and its subsidiary, described above, has been omitted but will be furnished to the Commission upon request.

*** These exhibits represent a management contract or compensatory plan.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 18, 2009

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board of Directors,
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 18, 2009
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 18, 2009
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	February 18, 2009
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 18, 2009
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 18, 2009
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 18, 2009
/s/ CHARLES H. TENNEY, III **Charles H. Tenney, III**	Director	February 18, 2009
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 18, 2009
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 18, 2009
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 18, 2009
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 18, 2009
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 18, 2009
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	February 18, 2009

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2008	2007	2006
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$9,735**	$8,746	$8,033
Less: Dividend Requirements on Preferred Stock	**135**	136	133
Net Income Applicable to Common Stock	**$9,600**	$8,610	$7,900
Average Number of Common Shares Outstanding—Basic	**5,830**	5,659	5,597
Dilutive Effect of Stock Options and Restricted Stock	**—**	13	15
Average Number of Common Shares Outstanding—Diluted	**5,830**	5,672	5,612
Earnings Per Share—Basic	**$ 1.65**	$ 1.52	$ 1.41
Earnings Per Share—Diluted	**$ 1.65**	$ 1.52	$ 1.41

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2008	2007	2006	2005	2004
(000's, except ratios)					
Earnings:					
Net Income, per Consolidated Statement of Earnings	**$ 9,735**	$ 8,746	$ 8,033	$ 8,553	$ 8,226
Federal and State Income Taxes included in Operations	**4,450**	4,482	4,266	4,275	4,206
Interest on Long-Term Debt	**11,795**	10,919	9,404	8,319	8,394
Amortization of Debt Discount Expense	**151**	136	112	104	98
Other Interest	**1,156**	1,949	1,675	1,046	629
Total	**$27,287**	$26,232	$23,490	$22,297	$21,553
Fixed Charges:					
Interest of Long-Term Debt	**$11,795**	$10,919	$ 9,404	$ 8,319	$ 8,394
Amortization of Debt Discount Expense	**151**	136	112	104	98
Other Interest	**1,156**	1,949	1,675	1,046	629
Pre-tax Preferred Stock Dividend Requirements	**199**	213	208	234	325
Total	**$13,301**	$13,217	$11,399	$ 9,703	$ 9,446
Ratio of Earnings to Fixed Charges	**2.05**	1.98	2.06	2.30	2.28

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has eight wholly-owned subsidiaries, seven of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Northern Utilities, Inc., Granite State Gas Transmission, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The eighth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements of Unitil Corporation and subsidiaries on Form S-3 (File No. 333-152823 effective December 5, 2008), Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000) of our report dated February 13, 2009, relating to the consolidated financial statements of Unitil Corporation and subsidiaries (the Company) as of December 31, 2008 and 2007 and the three years ending December 31, 2008 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2008, appearing in the Annual Report of the Company on Form 10-K for the year ended December 31, 2008.

Vitale, Caturano & Company, P.C.

Boston, Massachusetts
February 17, 2009

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2009

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2009

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2009

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 18, 2009
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 18, 2009
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 18, 2009

Shareholder Information

2009 Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at the office of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 16, 2009, at 10:30 a.m.

Investor Information

The Company's Transfer Agent, Computershare Trust Company, N.A. ("Computershare"), is responsible for all shareholder records, including stock transfer and the distribution of dividends, tax documents and annual meeting materials. Shareholder requests regarding these and other matters can be addressed by corresponding directly with Computershare at:

Mail:	P.O. Box 43078 Providence, RI 02940-3078
Telephone:	800-736-3001
Internet:	ww.computershare.com

For information about the Company and your investment, you may also call the Company directly, toll-free, at: 800-999-6501 and ask for the Shareholder Representative; or visit the Investor Relations page at www.unitil.com.

Shareholder Programs

Dividend Reinvestment Plan

A Dividend Reinvestment and Stock Purchase Plan is available to all holders of record of the Company's Common Stock. This Plan provides shareholders with an economical means to increase their investment in the Company each quarter by reinvesting their dividends without broker fees. For additional information or enrollment, please contact the Company or Computershare.

Dividend Direct Deposit

Dividend Direct Deposit Service is available without charge to shareholders of record of the Company's Common Stock. For further information or enrollment in this service, please contact the Company or Computershare.

Direct Registration

The Company's Common Stock is eligible for Direct Registration or "DRS," which is available without charge to shareholders of record. DRS is a service within the securities industry that allows shares to be held and tracked electronically, without having to retain a physical stock certificate. For additional information, please contact Computershare at:

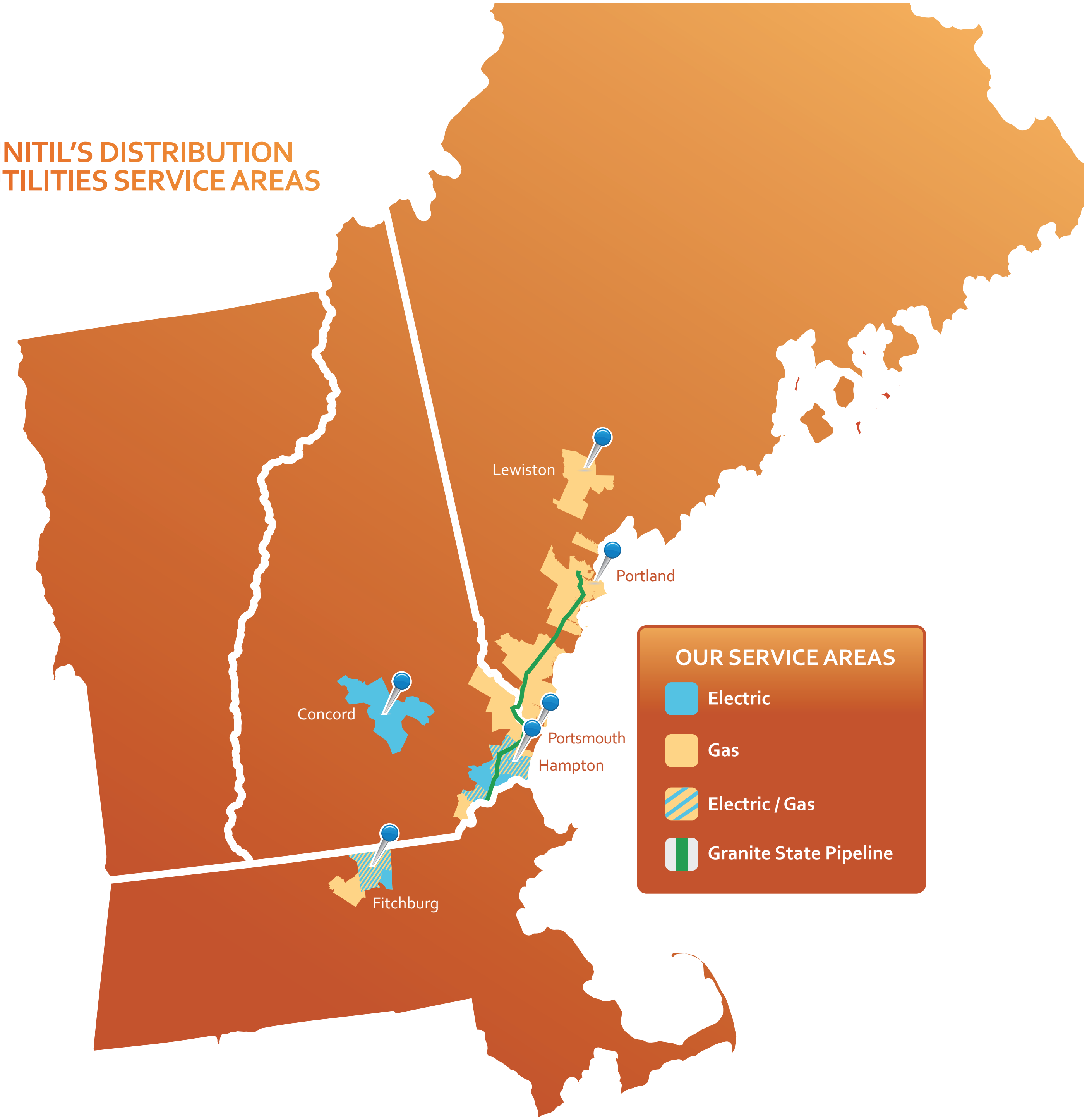
Mail:	P.O. Box 43084 Providence, RI 02940-3084
Telephone:	800-935-9330
Internet:	www.computershare.com

Unitil Corporation • 6 Liberty Lane West • Hampton, NH 03842-1720
603-772-0775 • www.unitil.com

002CS-17860

Annual Report 2009

UNITIL'S DISTRIBUTION UTILITIES SERVICE AREAS



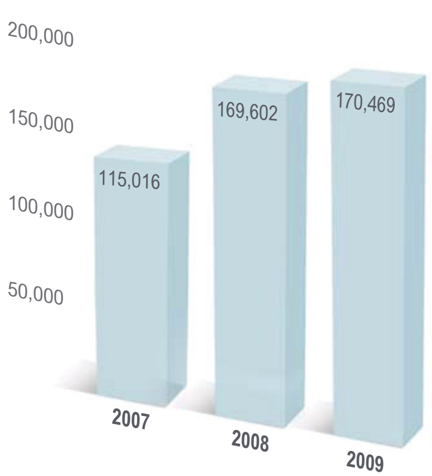
ABOUT UNITIL

Unitil Corporation is a public utility holding company headquartered in Hampton, New Hampshire. Unitil's principal business is the local distribution of electricity and natural gas in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three distribution utilities: Unitil Energy Systems, Inc., which provides electric service in the southeastern seacoast and state capital regions of New Hampshire; Fitchburg Gas and Electric Light Company, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and Northern Utilities, Inc., which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine. In addition, Unitil is the parent company of Granite State Gas Transmission, Inc., an interstate natural gas transmission pipeline in New Hampshire and Maine. Unitil's non-regulated business, Usource, provides energy brokering and advisory services to large commercial and industrial customers throughout the northeastern United States.

FINANCIAL HIGHLIGHTS*

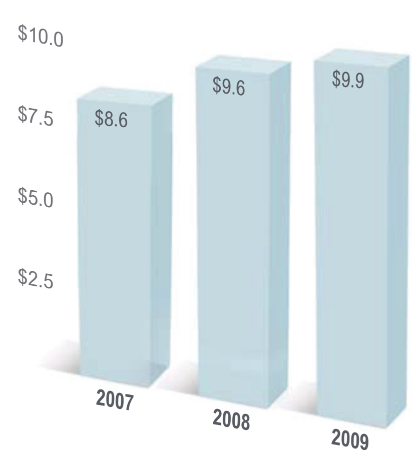
	2009	2008	2007
Financial Data (Millions)			
Total Operating Revenues	$367.0	$288.2	$262.9
Total Operating Income	$26.1	$20.5	$18.5
Earnings Applicable to Common	$9.9	$9.6	$8.6
Capital Expenditures	$58.7	$28.3	$32.5
Net Utility Plant	$449.7	$422.8	$248.9
Common Share Data			
Diluted Earnings per Share	$1.03	$1.65	$1.52
Dividends Paid Per Common Share	$1.38	$1.38	$1.38
Book Value Per Share (Year-End)	$17.83	$17.90	$17.50
Market Price (Year-end)	$22.98	$20.65	$28.51
Average Common Shares Outstanding (000's)	9,647	5,830	5,672
Operating Data			
Electric Distribution Sales (Millions of kWh)	1,618.8	1,695.9	1,743.0
Firm Gas Distribution Sales (Millions of Therms)	178.7	47.2	28.4
Customers Served (Year-End)	170,469	169,602	115,016
Electric Customers Served (Year-End)	100,498	100,324	99,947
Gas Customers Served (Year-End)	69,971	69,278	15,069

Total Customers Served
(year-end)



Net Utility Plant
($ millions)

Earnings Applicable to Common
($ Millions)



* Financial Highlights reflect Unitil's acquisition on December 1, 2008, of Northern Utilities, Inc. and Granite State Gas Transmission, Inc.

Robert G. Schoenberger
Chairman of the Board of Directors,
President and Chief Executive Officer

TO our SHAREHOLDERS

2009 was a new chapter in your Company's history.

We successfully completed the financing and integration of our acquisition of Northern Utilities and the Granite State Gas Transmission pipeline. The acquisition increased our customer base by 50%, adding almost 55,000 natural gas customers in Maine and New Hampshire. It doubled our sales margin and diversified our earnings base, producing a Company that is equally balanced between electric and natural gas operations. Our ability to acquire these utility assets, to finance them in the most difficult financial markets in a generation, and to seamlessly integrate such operations into Unitil positions us well for future growth opportunities.

We welcomed 145 new employees to our Company last year, which includes the existing employees of Northern Utilities and Granite State and 65 new professional positions added to the local economy during a deep recession. We attracted first rate talent to staff new utility operations with employees that add depth to our management and our technical expertise.

We also dealt with a number of legacy issues arising from the devastating ice storm of December 2008. We completed comprehensive legislative and regulatory reviews of our performance during the storm and completed an independent, in-depth review of our emergency preparedness processes and procedures. Every employee is now trained for a second internal job in the event of an emergency. We have invested in new systems and technology, including an outage management system, to keep state and local officials and our customers well informed during an event. We conducted several full-scale emergency planning drills during the year and will do so again each year to ensure we remain prepared. Our employees responded heroically to the incredible challenges posed for our Company by the ice storm of December 2008 and its aftermath.

Our overarching commitment to our shareholders over the next several years is to increasingly realize the earnings power of our Company and fully exploit new growth opportunities that enhance shareholder value. Our updated strategic plan focuses on three main areas: regulation, customer service, and growth. I will discuss each of these areas below.

2009 Financial Results

2009 financial results were well below our expectations. We earned $1.03 per share in 2009 compared to $1.65 per share in 2008. Our results in 2009 were impacted unfavorably by two significant non-recurring items.

First, we incurred $3 million in professional fees specifically related to various regulatory and legislative inquiries and to the comprehensive review and enhancement of our emergency preparedness plans in the aftermath of the December 2008 ice storm. Second, we were ordered by the Massachusetts Department of Public Utilities to refund $4.9 million of natural gas supply costs to our Fitchburg customers as the result of a finding, with which we strongly disagree, related to the Company's gas supply procurement practices. While this refund will be made over a five-year period, we recognized a one time non-recurring accounting charge for this amount. We appealed this order to the Massachusetts Judicial Supreme Court and believe we have a strong case to overturn this decision. The appeal process likely will take a couple of years to complete.

Excluding these two non-recurring charges, we earned $1.57 per share in 2009, or eight cents per share less than the previous year. We believe this is more reflective of the core earnings of our Company in 2009, particularly given the impact of the ongoing recession on our sales. It is clear, however, that our Company was "stress tested" over the last 12 months. We confronted these challenges and are stronger as a result.

Our Company spent almost $23 million for the repair and replacement of electric distribution systems damaged last year. This represents nearly half of what we spent in 2009 on normal property, plant, and equipment needs. Massachusetts and New Hampshire regulatory officials approved orders allowing us to defer these costs and to seek future recovery in our next rate cases. We expect those reviews to begin in 2010.

The current economic downturn is one of the worst we have seen in a generation. We have seen our electric sales decline in each of the last four years. Although recently sales have stabilized, we expect 2010 to be another challenging year and have implemented strong cost control measures, including a pay and hiring freeze for the year, to help navigate this recession. We are continuously mindful of how this economy is adversely affecting our customers and state and local communities.

We also understand how important the dividend is to our shareholders. Despite the challenges we faced last year and expect in 2010, we have continued to pay a quarterly dividend of $0.34 per share, or $1.38 annually. Our Company's tradition of paying quarterly dividends has been uninterrupted since public trading of Unitil common stock began in 1985.

2010 is an important transition year for our Company. Our challenge is to manage costs as we execute a full regulatory agenda over the next two years to realize the full earnings power of our Company. We will continue to capitalize on the excellent growth prospects of our Usource subsidiary. We will aggressively explore the opportunity to expand our distribution footprint in the region. And we will do all this while reinforcing the level of reliability and quality of customer service our customers have come to expect.

Regulatory Agenda

Our Company has a full regulatory agenda ahead. We plan to file rate cases for most of our regulated utilities over the next 24 months. These proceedings will provide us an opportunity to update our base distribution rates to recover the significant capital investments made since our last rate case filings. In 2010, we plan to file rate cases for our distribution utilities in New Hampshire and Massachusetts. In addition, we will establish new rates for the Granite State Transmission pipeline later this year.

In Massachusetts we will seek to establish a revenue "decoupling" mechanism pursuant to a recently established regulatory policy designed to support the aggressive energy efficiency expansion initiative by the state's utilities. As the word would suggest, decoupling refers to a rate mechanism that separates the revenues a utility earns from the sales it makes. This model allows a utility to implement energy conservation policies and initiatives without adversely impacting its revenues. Revenue decoupling also helps mitigate the impact of various factors, including weather and the economy, on our financial returns.

We will propose a systematic cast iron replacement program, with an appropriate cost recovery proposal, for our newly acquired gas division in Maine this year. In 2011, we plan to file our first base rate case in Maine to recover past capital investments and to update rates to reflect our cost of service. We have completed many of the required post-acquisition reliability and safety projects for our gas operations, earning compliments from Maine regulatory officials for completing this work and for implementing new systems to ensure compliance with federal and state gas safety standards.

Customer Service

In July of 2009, we completed a successful and seamless integration of our new natural gas customers in New Hampshire and Maine into our Customer Information System and we welcomed their calls into our central Customer Service Center. The smoothness of this transition, complete within seven months of the acquisition, received high marks from customers and regulators in both states.

However, the problems we had communicating with our customers during the 2008 ice storm clearly showed we had a significant opportunity for improving service and communications in extreme emergency situations. We have renewed our commitment to first class customer service in significant ways, including adding new personnel, new technology, and new processes – all designed to make two-way communications easier and more user-friendly.

We started by completely overhauling our emergency preparedness plan and procedures. We adopted the national incident management system to focus the resources of the entire organization on responding to an emergency. This system, developed for federal emergency management purposes and now in use by many state and local governments and a number of utilities throughout the country, establishes a management infrastructure to marshal the resources of our Company to respond to an emergency in a safe and effective manner. We have met with emergency personnel in the communities we serve to coordinate planning efforts and to ensure we all can respond effectively to future events. Every employee in our Company has an assigned job during an emergency event. They will participate in emergency response drills each year to equip them with the latest training and best methods to respond to the needs of our customers during an event.

We also have hired additional call center personnel and have made significant investments in hardening our communications and technology infrastructure to ensure availability in emergency situations. We are in the process of redesigning our Company website to provide another interactive source of information for our customers, including the ability to use instant and mobile forms of communication, such as Twitter and Facebook, to communicate important updates and information.

We continued initiatives developed over the past few years to significantly upgrade our technology infrastructure and reliability for the next decade. We installed an advanced metering infrastructure (AMI) that provides two-way automatic meter reading and communications capabilities for all of our electric customers, an important step to meet the needs of the ongoing industry evolution toward energy efficiency and alternative energy technologies. The Company's AMI is being integrated with our other advanced technologies, including a state-of-the-art outage management system. In addition, we will conduct a pilot program in both Massachusetts and New Hampshire in 2010 on the deployment of advanced rate and information tools for customers using the AMI backbone. The pilot is one of several initiatives to gain an understanding of how all these technologies ultimately will work together in the operation of a truly smart grid.

Finally, we adopted new customer service performance metrics to ensure that we are being responsive to our customers needs. Unitil has long prided itself on having customer satisfaction ratings well above the national utility average; we are determined to meet the highest standards in the industry.

Growth

Our Company will continue to capitalize on its growth opportunities. We will market aggressively the increased use of natural gas to all our customer segments throughout the three states in which we operate, where the average penetration rate of natural gas as a heating fuel is only about 40%, compared to a nationwide rate of 80% to 90%. As the national supply of cost-effective, safe, and clean natural gas continues to expand, our Company has a timely opportunity to significantly increase its natural gas sales and regional market share.

We will explore real opportunities to acquire additional electric and gas utility distribution assets in the region. Having proved that we can acquire, finance, and integrate distribution assets and new customers into our systems, we are well positioned to acquire such assets for the right price if and when they should become available. We believe we have the management, technology, and service expertise to make additional asset acquisitions efficient and profitable for shareholders.

Usource earned $0.16 a share in 2009, triple its contribution in 2008. This was a result of a reduction in operating expenses, a customer retention rate of over 90%, and increased sales in its existing markets. As we look out at 2010 and beyond, we believe Usource has the opportunity to further contribute to our Company's bottom line. Pennsylvania is a major new market opportunity opening in 2010 and we are already there acquiring customers. As an energy broker serving customers in 18 states, Usource is a low-cost and low-risk vehicle for large energy users to participate in competitive energy markets for the electric and natural gas supply.

Summary

2009 was an incredibly challenging year. We completed a significant acquisition and added 55,000 natural gas customers in Maine and New Hampshire, doubling the size of Unitil. We responded to the aftermath of an epic ice storm. Juggling the demands of both these efforts, while running our Company during the worst recession in a generation, required all of our abilities and talents. We received both compliments and some intense criticism. Through it all we have emerged a stronger and more determined Company. I want to thank each of our employees who so gallantly rose to the challenges put before them. I also want to thank our shareholders, who supported us through these difficult times.

We have built a strong and talented team and have a solid plan to capitalize on our core competencies to grow our Company in a prudent and responsible manner. We take your investment in Unitil seriously and are committed to realizing its full value in the years ahead.

Robert G. Schoenberger
Chairman of the Board of Directors,
President and Chief Executive Officer

February 19, 2010

This Annual Report contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather (including major storms); recovery of deferred storm costs; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; interest rate fluctuations and credit market concerns; and other risks and uncertainties described in the section entitled *Risk Factors* in the enclosed Annual Report on Form 10-K and Unitil Corporation's other filings with the Securities and Exchange Commission. Forward-looking statements speak only as of the date made, and the Company undertakes no obligation to update any forward-looking statements. Please also see *Cautionary Statement* beginning on page 22 of the enclosed Form 10-K.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire (State or other jurisdiction of incorporation or organization)	**02-0381573** (I.R.S. Employer Identification No.)
6 Liberty Lane West, Hampton, New Hampshire (Address of principal executive offices)	**03842-1720** (Zip Code)

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Based on the closing price of June 30, 2009, the aggregate market value of common stock held by non-affiliates of the registrant was $219,996,265.

The number of common shares outstanding of the registrant was 10,838,394 as of February 9, 2010.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010 are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2009
Table of Contents

[THIS PAGE INTENTIONALLY LEFT BLANK]

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly owned subsidiaries of Unitil:

Company Name	State and Year of Organization	Principal Business
Unitil Energy Systems, Inc. (Unitil Energy)	NH - 1901	Electric Distribution Utility
Fitchburg Gas and Electric Light Company (Fitchburg)	MA - 1852	Electric & Gas Distribution Utility
Northern Utilities, Inc. (Northern Utilities)	NH - 1979	Natural Gas Distribution Utility
Granite State Gas Transmission, Inc. (Granite State)	NH - 1955	Natural Gas Transmission Pipeline
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-regulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering and Advisory Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territories in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly owned distribution utilities: i) Unitil Energy, which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the city of Concord, New Hampshire, ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts, and iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area. In addition, Unitil is the parent company of Granite State, an interstate natural gas transmission pipeline company that provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory. Together, Unitil's three distribution utilities serve approximately 100,500 electric customers and 70,000 natural gas customers.

Unitil's distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in net utility plant of $449.7 million at December 31, 2009. Unitil's total operating revenue was $367.0 million in 2009. Substantially all of Unitil's operating revenue is derived from regulated utility operations.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are indirect subsidiaries that are wholly owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

OPERATIONS

Gas Operations

Unitil's Gas Operations include gas distribution utility operations and gas transportation pipeline company operations, discussed below. Revenue from Unitil's gas operations was $152.8 million for 2009, which represent about 42% of Unitil's total operating revenue. In 2008, the Company significantly expanded its gas operations by acquiring Northern Utilities and Granite State on December 1, 2008.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, originally founded as Portland Gas Light Company in 1849, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate natural gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the Acquisitions). Bay State is a wholly owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt (see "Liquidity, Commitments and Capital Requirements" section in Part II, Item 7 below). The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features (See Note 6 to the accompanying Consolidated Financial Statements for additional information on these settlement agreements).

Gas Distribution Utility Operations

Unitil's natural gas utility operations are conducted through two of the Company's distribution utilities, Northern Utilities and Fitchburg. The primary business of Unitil's natural gas utility operations is the local distribution of natural gas to customers in its service territory in New Hampshire, Massachusetts and Maine. As a result of a restructuring of the gas utility industry in New Hampshire, Massachusetts and Maine, Fitchburg's residential and commercial and industrial (C&I) customers and Northern Utilities' C&I customers have the opportunity to purchase their natural gas supplies from third-party energy supply vendors. Most customers, however, continue to purchase such supplies through Northern Utilities and Fitchburg under regulated rates and tariffs. Northern Utilities and Fitchburg purchase natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis through reconciling rate mechanisms that are periodically adjusted.

Natural gas is supplied and distributed by Northern Utilities to approximately 54,800 customers in 44 New Hampshire and southern Maine communities, from Plaistow, New Hampshire in the south to the city of Portland, Maine and then extending to Lewiston-Auburn, Maine in the north. Northern Utilities has a diversified customer base both in Maine and New Hampshire. Commercial businesses include healthcare, education, government and retail. Northern Utilities' industrial base includes manufacturers in the industries of auto, housing, rubber, printing, textile, pharmaceutical, electronics, wires and food production as well as a military installation. Northern Utilities 2009 gas operating revenue was $113.9 million, of which approximately 37.0% was derived from residential firm sales and 63.0% from C&I firm sales.

Natural gas is supplied and distributed by Fitchburg to approximately 15,200 customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. Fitchburg's 2009 gas operating revenue was $34.8 million, of which approximately 54.0% was derived from residential firm sales and 46.0% from commercial/industrial firm sales.

Gas Transmission Pipeline Company Operations

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State

provides Northern Utilities with interconnection to major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State had operating revenue of $4.1 million for 2009. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Electric Distribution Utility Operations

Unitil's electric utility operations are conducted through two of the Company's distribution utilities, Unitil Energy and Fitchburg. Revenue from Unitil's electric utility operations was $209.9 million for 2009, which represent about 57% of Unitil's total operating revenue.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its service territory in New Hampshire and Massachusetts. As a result of the implementation of choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The distribution utilities continue to deliver that supply of electricity over their distribution systems. Both Unitil Energy and Fitchburg supply electricity to those customers who do not obtain their supply from third-party suppliers, with the approved costs associated with electricity supplied by the distribution utilities being recovered on a pass-through basis under periodically-adjusted rates.

Unitil Energy distributes electricity to approximately 72,600 customers in New Hampshire in the capital city of Concord as well as parts of 12 surrounding towns and all or part of 18 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. Unitil Energy's service territory consists of approximately 408 square miles. In addition, Unitil Energy's service territory encompasses retail trading and recreation centers for the central and southeastern parts and includes the Hampton Beach recreational area. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics, healthcare and education. Unitil Energy's 2009 electric operating revenue was $146.4 million, of which approximately 51.0% was derived from residential sales and 49.0% from commercial/industrial sales.

Fitchburg is engaged in the distribution of both electricity and natural gas in the greater Fitchburg area of northcentral Massachusetts. Fitchburg's service territory encompasses approximately 170 square miles. Electricity is supplied and distributed by Fitchburg to approximately 27,900 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries and education. Fitchburg's 2009 electric operating revenue was $63.5 million, of which approximately 54.0% was derived from residential sales and 46.0% from commercial/industrial sales.

Seasonality

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company's results will reflect the seasonal nature of the natural gas distribution business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours. Unitil Energy, Fitchburg and Northern Utilities are not dependent on a single customer or a few customers for their electric and natural gas sales.

Non-regulated and Other Non-Utility Operations

Unitil's non-regulated operations are conducted through Usource, a subsidiary of Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's non-regulated operations was $4.3 million in 2009.

The results of Unitil's other non-utility subsidiaries, Unitil Service and Unitil Realty, and the holding company are included in the Company's consolidated results of operations. The results of these non-utility operations are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and are reported, after intercompany eliminations, in Other segment income (for segment information, see Part II, Item 8, Note 10 herein).

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 with regard to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, with regard to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and Maine Public Utilities Commission (MPUC). Granite State, Unitil's interstate natural gas transmission pipeline, is subject to regulation by the FERC with regard to their rates and operations. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party energy supply vendors. Most customers, however, continue to purchase such supplies through the distribution utilities under regulated energy rates and tariffs. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual approved costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

On December 11 and 12, 2008, a severe ice storm struck the New England region (December 2008 Ice Storm), causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers.

The Company has received regulatory approval to defer storm restoration costs and has accrued and deferred approximately $14.6 million of costs, including carrying charges, incurred for the repair of its electric system damaged during the ice storm so that it may seek recovery of these costs in its next base rate cases. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, there may be a significant impact on the Company's results of operations in future periods.

Also see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Rates and Regulation.

NATURAL GAS SUPPLY

With the purchase of Northern Utilities on December 1, 2008, Unitil now manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and C&I customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, although most of Fitchburg's customers continue to purchase such supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply at regulated rates from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

In the fourth quarter of 2009, the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus carrying charges, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. Fitchburg has appealed this order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of LNG or LPG, to truck supplies to each storage facility within Northern Utilities' service territory.

Northern has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

ELECTRIC POWER SUPPLY

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third party energy suppliers. As of December 2009, 99 or 67% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 79% of Unitil's largest Massachusetts customers, representing 35% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential and small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

Prior to May 1, 2003, Unitil Energy purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, Unitil Energy and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to Unitil Energy ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, Unitil Energy continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. In connection with the restructuring of the electric industry, Unitil Power and Fitchburg divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts.

Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

ENVIRONMENTAL MATTERS

Unitil's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed. Also, see Note 6 to the accompanying consolidated financial statements.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800's through the mid 1900's. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Also, see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES

As of December 31, 2009, the Company and its subsidiaries had 431 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2009, 156 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two agreements expire on May 31, 2010, one agreement expires on June 5, 2010 and one agreement expires on March 31, 2012. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is *www.unitil.com*. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the New York Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 10, 2010:

Name	Age	Position
Robert G. Schoenberger	59	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	50	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	47	Senior Vice President and Chief Operating Officer
Laurence M. Brock	56	Controller and Chief Accounting Officer
Todd R. Black	45	Senior Vice President, External Affairs and Customer Relations, Unitil Service
George R. Gantz	58	Senior Vice President, Distributed Energy Resources, Unitil Service
George E. Long, Jr.	53	Vice President, Administration, Unitil Service
Sandra L. Whitney	46	Corporate Secretary
William D. Adams	62	Director
Dr. Robert V. Antonucci	64	Director
David P. Brownell	66	Director
Michael J. Dalton	69	Director
Albert H. Elfner, III	65	Director
Edward F. Godfrey	60	Director
Michael B. Green	60	Director
Eben S. Moulton	63	Director
M. Brian O'Shaughnessy	66	Director
Dr. Sarah P. Voll	67	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board of Directors and Chief Executive Officer since 1997, as well as President since 2003. Prior to his employment with Unitil, Mr. Schoenberger was president and chief operating officer of the New York Power Authority (a state-owned utility) from 1993 until 1997. Mr. Schoenberger has also served as a director of SatCon Technology Corporation, Boston, Massachusetts (a company engaged in the development and manufacture of power electronics and control systems) since 2007. Mr. Schoenberger formerly served as chairman and trustee of Exeter Health Resources, Exeter, New Hampshire, from 1998 until 2009, and as a director of the Greater Seacoast (New Hampshire) United Way from 1998 until 2004, the New England Gas Association from 1999 until 2002 and the Southwest Power Pool from 2003 until 2005.

Mark H. Collin has been Unitil's Senior Vice President and Chief Financial Officer since February 2003. Mr. Collin has also served as Treasurer since 1998. Mr. Collin joined Unitil in 1988, and served as Vice President of Finance from 1995 until 2003.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President and Chief Operating Officer since June 2005. Mr. Meissner served as Senior Vice President, Operations, from February 2003 until June 2005. Mr. Meissner joined Unitil in 1994 and served as Director of Engineering from 1998 until 2003.

George R. Gantz has been Unitil's Senior Vice President, Distributed Energy Resources, Unitil Service, since September 2009. Mr. Gantz joined Unitil in 1983 and served as Senior Vice President, Communication and Regulation from 1994 until 2003, and Senior Vice President, Customer Services and Communications from 2003 until 2009.

Todd R. Black has been Unitil's Senior Vice President, External Affairs and Customer Relations, Unitil Service, since September 2009. Mr. Black joined Unitil in 1998 and served as Vice President, Sales and Marketing, for Usource from 1998 until 2003, and President of Usource from 2003 until 2009.

Laurence M. Brock has been Unitil's Controller and Chief Accounting Officer since June 2005. Mr. Brock joined Unitil in 1995 as Vice President and Controller, and is a certified public accountant in the state of New Hampshire.

George E. Long, Jr. has been Unitil's Vice President, Administration, Unitil Service, since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources, from 1998 until 2003.

Sandra L. Whitney has been Unitil's Corporate Secretary and secretary of our Board of Directors since February 2003. Ms. Whitney joined Unitil in 1990 and also serves as the Corporate Secretary of Unitil's subsidiary companies.

William D. Adams has been a member of Unitil's Board of Directors since 2009. Mr. Adams has been the president of Colby College in Waterville, Maine, since 2000. Mr. Adams also serves on the board of trustees of Colby College. Mr. Adams also served as president of Bucknell University (Bucknell) in Pennsylvania from 1995 until 2000. Prior to leading Bucknell, he served as vice president and secretary of Wesleyan University in Connecticut. Mr. Adams also served as coordinator of the Great Works in Western Culture program at Stanford University and taught political philosophy at the University of North Carolina at Chapel Hill and Santa Clara University. Mr. Adams has served on the board of directors of Wittenburg University since 2007, Maine General Health since 2002, and Maine Public Broadcasting Corporation since 2002.

Dr. Robert V. Antonucci has been a member of Unitil's Board of Directors since 2004. Dr. Antonucci has been the president of Fitchburg State College (FSC) in Fitchburg, Massachusetts, since 2003. Prior to his employment with FSC, Dr. Antonucci was president of the School Group of Riverdeep, Inc., San Francisco, California, from 2001 until 2003 and president and chief executive officer of Harcourt Learning Direct and Harcourt Online College, Chestnut Hill, Massachusetts from 1998 until 2001. Dr. Antonucci also served as the commissioner of education for the Commonwealth of Massachusetts from 1992 until 1998. In addition, Dr. Antonucci has served as a trustee of Eastern Bank since 1988. Dr. Antonucci also serves and a director of the North Central Massachusetts Chamber of Commerce and a director of the North Central Massachusetts United Way.

David P. Brownell has been a member of Unitil's Board of Directors since 2001. Mr. Brownell has been a retired senior vice president of Tyco International Ltd. (Tyco) (a diversified global manufacturing and service company), Portsmouth, New Hampshire, since 2003. Mr. Brownell had been with Tyco since 1984. Mr. Brownell was also interim president of the University of New Hampshire (UNH) Foundation, former vice chairman of the board of UNH Foundation, former volunteer board president of the United Way of the Greater Seacoast, and a former board member of the New Hampshire Junior Achievement Advisory Council.

Michael J. Dalton has been a member of Unitil's Board of Directors since 1984. Mr. Dalton has been the retired president and chief operating officer of Unitil since 2003. Mr. Dalton has been a member of the Industrial Advisory Council of the University of New Hampshire College of Engineering and Physical Sciences since 2003, and vice president since 2009. Mr. Dalton was a director of the New England Gas Association from 2002 until 2003, the Electric Council of New England, the UNH Foundation, the University of New Hampshire Alumni Association, and the University of New Hampshire President's Council. In addition, Mr. Dalton serves as a mentor with the University of New Hampshire Pathways Mentorship Program.

Albert H. Elfner, III has been a member of Unitil's Board of Directors since 1999. Mr. Elfner was the chairman of Evergreen Investment Management Company, Boston, Massachusetts, from 1994 until 1999 and its chief executive officer from 1995 until 1999. Mr. Elfner is also a director of NGM Insurance Company (NGM), Jacksonville, Florida, as well as a member of the NGM finance committee, and as a director of Emerson Ecologics, LLC (distributor of natural health care products to health care professionals), and as a trustee of MDT Advisors (a quantitative investment management firm), Boston, Massachusetts.

Edward F. Godfrey has been a member of Unitil's Board of Directors since 2002. Mr. Godfrey was the executive vice president and chief operating officer of Keystone Investments, Incorporated (Keystone), Boston, Massachusetts, from 1997 until 1998. Mr. Godfrey was senior vice president, chief financial officer and treasurer of Keystone from 1988 until 1996. Mr. Godfrey is also a director of VehiCare, LLC, Charlotte, North Carolina, since 2006.

Michael B. Green has been a member of Unitil's Board of Directors since 2001. Mr. Green has been the president and chief executive officer of Capital Region Health Care and Concord Hospital, Concord, New Hampshire, since 1992. Mr. Green is also a member of the adjunct faculty, Dartmouth Medical School, Dartmouth College, Hanover, New Hampshire. In addition, Mr. Green currently serves on the board of the Foundation for Healthy Communities, is a director of the New Hampshire Hospital Association, a director of New Hampshire Business Council for the Arts, and a director of Merrimack County Savings Bank including membership on the bank's investment and audit committees.

Eben S. Moulton has been a member of Unitil's Board of Directors since 2000. Mr. Moulton has been the managing partner of Seacoast Capital Corporation, Danvers, Massachusetts, (a private investment company) since 1995. Mr. Moulton is also a director of IEC Electronics (provider of electronic manufacturing services to advanced technology companies), Newark, New York, a director of six private companies, and a trustee of Colorado College, Colorado Springs, Colorado.

M. Brian O'Shaughnessy has been a member of Unitil's Board of Directors since 1998. Mr. O'Shaughnessy has been the chairman of the board of Revere Copper Products, Inc. (Revere), Rome, New York, since 1988. Mr. O'Shaughnessy also served as chief executive officer and president of Revere from 1988 until 2007. Mr. O'Shaughnessy also serves on the Board of Directors and as the chief co-chair of the Coalition for a Prosperous America, three copper industry trade associations, three manufacturing associations in New York State regarding energy-related issues, and the Economic Development Growth Enterprise of Mohawk Valley.

Dr. Sarah P. Voll has been a member of Unitil's Board of Directors since 2003. Dr. Voll has been a retired vice president, National Economic Research Associates, Inc. (NERA), Washington, District of Columbia, a firm of consulting economists specializing in industrial and financial economics, since 2007, but currently serves as a special consultant to NERA. Dr. Voll had been with NERA in the position of vice president since 1999, and in the position of senior consultant from 1996 until 1999. Prior to her employment with NERA, Dr. Voll was a staff member at the NHPUC from 1980 until 1996.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 15, 2010, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of common stock, administration of the Dividend Reinvestment and Stock Purchase Plan, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Computershare
P.O. Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

Investor Relations

For information about the Company, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at *www.unitil.com*; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available to Holders of Record

If a shareholder's shares of common stock are registered directly in the shareholder's name with the Company's transfer agent, the shareholder is considered a holder of record of the shares. The following services and programs are available to shareholders of record:

- Internet Account Access is available at *www.computershare.com*.
- Dividend Reinvestment and Stock Purchase Plan:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Direct Registration:

  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

Risks related to the regulation of the Company's business could impact the rates it is able to charge, its costs and its profitability.

The Company is subject to comprehensive regulation by federal and state regulatory authorities, which significantly influences the Company's operating environment and its ability to recover costs from its customers. In particular, the Company is regulated by the FERC and state regulatory authorities with jurisdiction over public utilities, including the NHPUC, MDPU and MPUC. These authorities regulate many aspects of the Company's operations, including, but not limited to, construction and maintenance of facilities, operations, safety, issuance of securities, accounting matters, transactions between affiliates, the rates that the Company can charge customers and the rate of return that it is allowed to realize. The Company's ability to obtain rate adjustments to maintain its current rate of return depends upon regulatory action under applicable statutes, rules and regulations, and the Company cannot assure you that it will be able to obtain rate adjustments or continue receiving its current authorized rates of return. These regulatory authorities are also empowered to impose financial penalties and other sanctions on the Company if it is found to have violated statutes and regulations governing its utility operations. The Company is unable to predict the impact on its operating results from the regulatory activities of any of these agencies. Although the Company has attempted to actively manage the rate making process and has had recent success in obtaining rate adjustments, it can offer no assurances as to future success in the rate making process. Despite the Company's requests, these regulatory commissions have authority under applicable statutes, rules and regulations to leave the Company's rates unchanged, grant increases or order decreases in such rates.

The regulators also have authority with respect to the recovery of the Company's electricity and natural gas supply costs incurred by Unitil Energy, Fitchburg, and Northern Utilities. In the event that the Company is unable to recover a significant amount of these costs or recovery of these costs were to be significantly delayed, the Company's operating results could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have an adverse effect on the Company's operating results.

In the fourth quarter of 2009, the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus carrying charges, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

The Company has deferred certain costs associated with the December 2008 Ice Storm for future recovery in rates.

On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers.

The Company has received regulatory approvals to defer storm restoration costs and has accrued and deferred approximately $14.6 million of costs, including carrying charges, for the repair of its electric system damaged during the December 2008 Ice Storm so that it may seek recovery of these costs in its next base rate cases. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, there may be a significant impact on the Company's results of operations in future periods.

As a result of electric industry restructuring, the Company has a significant amount of certain stranded electric generation and generation related supply costs.

The stranded costs resulting from the implementation of electric industry restructuring mandated by the states of New Hampshire and Massachusetts are recovered by the Company on a pass-through basis through periodically reconciled rates. Any unrecovered balance of purchased power or stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

The Company's power supply-related regulatory assets due to the electric industry restructuring in New Hampshire and Massachusetts for which regulatory approval has been obtained for recovery were approximately $25.6 million for Fitchburg and $9.1 million for Unitil Energy as of December 31, 2009, including $8.4 million and $4.6 million for Fitchburg and Unitil Energy, respectively, recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Additionally, the Company's other restructuring-related regulatory assets for which regulatory approval has been obtained for recovery were approximately $28.3 million in the aggregate as of December 31, 2009, including $4.7 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet.

Substantially all of Fitchburg's stranded costs relate to owned generation assets and purchase power agreements divested by Fitchburg under a long-term contract buy-out agreement. Unitil Energy's stranded costs are attributable to the long-term power purchase agreements divested by Unitil Power under long-term contract buyout agreements. Because Fitchburg and Unitil Power remain ultimately responsible for purchase power payments underlying these long-term buyout agreements, Fitchburg and Unitil Power could incur additional stranded costs were they required to resell such divested entitlements prior to the end of their term for amounts less than the amounts agreed to under the existing long-term buyout agreements. The Company expects that any such additional stranded costs would be recovered from its customers, although such recovery would require approval from the MDPU or NHPUC, the receipt of which cannot be assured.

The Company's electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may negatively impact the Company's customers and correspondingly its operating results and financial condition.

The Company's business is influenced by the economic activity within its service territory. The level of economic growth in the Company's electric and natural gas distribution service territory directly affects the potential for future growth in the Company's business. As a result, adverse changes in the economy may have negative effects on the Company's revenues, operating results and financial condition.

The Company may not be able to obtain financing or obtain financing on acceptable terms, which could have an adverse affect on the Company's operating results and financial condition.

The Company requires capital to fund utility plant additions, working capital and other utility expenditures. While the capital necessary to meet these requirements is derived primarily from internally-generated funds, the Company initially supplements internally generated funds through short-term debt under its current credit facility, as needed, and periodically replaces portions of its short-term debt with permanent financing sources such as long-term debt or equity. General economic conditions and the Company's operating and financial performance could negatively affect the Company's ability to obtain financing and the terms of such financing. In addition, the Company may be unable to obtain debt financing under its current credit facility because its lending counterparties may be unwilling or unable to meet their funding obligations. In each case, this could hinder or prevent the Company from meeting its current and future capital needs, which could correspondingly have an adverse affect on the Company's operating results and financial condition. In addition, the material terms of the Company's existing indebtedness restricts its ability to incur any material amount of additional indebtedness, which could negatively impact its operating results and financial condition. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

Declines in the valuation of capital markets could require the Company to make substantial cash contributions to cover its pension obligations, which could negatively impact its financial condition.

On August 17, 2006, the Pension Protection Act of 2006 (the PPA) was signed into law. Included in the PPA are new minimum funding rules which came into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period provided pursuant to the PPA. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 – 2010 plan years.

The Company made cash contributions of $4.2 million, $2.8 million and $2.8 million to its pension plan in 2009, 2008 and 2007, respectively, which exceeded minimum funding requirements. Recent and future declines in the valuation of capital markets could require the Company to make cash contributions to its pension plans substantially in excess of its cash contributions in prior years, which could adversely affect its financial condition.

The Financial Accounting Standards Board (FASB) guidance on accounting for pension and other post retirement benefit obligations requires companies to record on their balance sheets the funded status of their retirement benefit obligations (RBO). The Company has recognized a liability for the projected RBO of its plans and a corresponding regulatory asset, to recognize the future collection of these obligations in electric and gas rates. In the event that the Company is unable to recover these costs or recovery of these costs were to be significantly delayed, the Company's operating results could be materially adversely affected. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 9 to the accompanying Consolidated Financial Statements.

Increases in interest rates could have a negative impact on the Company's financial condition and the Company may need to use a significant portion of its cash flow to repay its outstanding indebtedness.

The Company and its utility subsidiaries have ongoing capital expenditure and cash funding requirements that they frequently fund by issuing short-term debt and long-term debt.

Short-term debt borrowings are typically at variable rates of interest. Therefore, changes in short-term interest rates will increase or decrease the Company's interest expense associated with short-term borrowings. Increases in interest rates generally will increase the Company's borrowing costs with respect to short-term debt and could adversely affect its financial condition or results of operations. As of December 31, 2009, the Company had approximately $64.5 million outstanding under its revolving credit facility.

Long-term debt borrowings are typically at fixed rates of interest. Therefore, changes in interest rates do not affect interest expense associated with presently outstanding fixed rate long-term debt securities. However, changes in interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities that are issued. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

The Company may need to use a significant portion of its cash flow to repay its short-term debt and long-term debt, which would limit the amount of cash it has available for working capital, capital expenditures and other general corporate purposes and could negatively affect its liquidity, financial condition and results of operations.

The Company's and its subsidiaries' indebtedness contains covenants that could restrict the Company's business operations.

See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

Weather conditions may cause the Company's sales to vary from year to year.

Sales by the Company's distribution utilities vary from year to year, depending on weather conditions. The Company estimates that approximately 50% of its annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of natural gas sold by the Company in any year, particularly during the winter heating season. The Company's electric sales are generally less sensitive to weather than its natural gas sales, but may also be affected by weather conditions in both the winter and summer seasons. The highest usage of electricity typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours.

The Company's results of operations reflect this seasonal nature. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by Northern Utilities, which was acquired by the Company on December 1, 2008. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Unitil is a holding company and has no operating income of its own. The Company's ability to pay dividends on its common stock is dependent on dividends received from its subsidiaries and on factors directly affecting Unitil, the parent corporation. The Company cannot assure you that its current annual dividend will be paid in the future.

Unitil is a public utility holding company and it does not have any operating income of its own. Consequently, the Company's ability to pay dividends on its common stock is dependent on dividends and other payments received from its subsidiaries, principally Unitil Energy, Fitchburg, Northern Utilities and Granite State. The ability of the Company's subsidiaries to pay dividends or make distributions to Unitil will depend on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of our subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by the Company's subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of Unitil Energy, Fitchburg, Northern Utilities and Granite State and that may be contained in future debt agreements of the Company's subsidiaries, if any; and
- limitations that may be imposed by New Hampshire, Massachusetts and Maine state regulatory agencies.

In addition, the Company may incur indebtedness in the future. Before the Company can pay dividends on its common stock, it has to satisfy its debt obligations and comply with any statutory or contractual limitations.

The Company's current annual dividend is $1.38 per share of common stock, payable quarterly. However, the Company's Board of Directors reviews Unitil's dividend policy periodically in light of the factors referred to above, and the Company cannot assure the amount of dividends, if any, that may be paid in the future.

Transporting and storing natural gas and supplemental gas supplies, as well as electricity, involves numerous risks that may result in accidents and other operating risks and costs.

Inherent in the Company's electric and natural gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions, electrocutions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, and impairment of the Company's operations and substantial losses to Unitil. In accordance with customary industry practice, the Company maintains insurance against some, but not all, of these risks and losses. The location of pipelines, storage facilities and electric distribution equipment near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect the Company's financial position and results of operations.

The Company's business is subject to environmental regulation in all jurisdictions in which it operates and its costs of compliance are significant. Any changes in existing environmental regulation and the incurrence of environmental liabilities could negatively affect the Company's results of operations and financial condition.

The Company's utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources, and the health and safety of the Company's employees. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; imposition of remedial requirements; and even issuance of injunctions to ensure future compliance. Liability under certain environmental laws is strict, joint and several in nature. Although the Company believes it is in general compliance with all applicable environmental and safety laws and regulations, there can be no assurance that significant costs and liabilities will not be incurred in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, could result in increased environmental compliance costs.

Catastrophic events could have a material adverse effect on the Company's financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could have a material adverse effect on the Company since they could inhibit its ability to continue providing electric and/or natural gas distribution services to its customers for an extended period, which is the principal source of the Company's operating income.

The Company's business could be adversely affected if it is unable to retain its existing customers or attract new customers.

The success of the Company's business depends, in part, on its ability to maintain and increase its customer base. The Company's failure to maintain or attract customers could have a material adverse effect on its business, financial condition and operating results.

The Company cannot guarantee customers' future performance under multi-year energy brokering contracts.

The Company's non-regulated energy brokering business provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenues from this business are primarily derived from brokering fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts. The Company cannot guarantee customers' future performance under multi-year energy brokering contracts.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2009, Unitil owned, through its distribution utilities, three utility operation centers, approximately 2,177 pole miles of local transmission and distribution overhead electric lines and 596 conduit bank miles of underground electric distribution lines, along with 48 electric substations, including three mobile electric substations. Our natural gas operations property includes two LPG plants, two LNG plants and 1,219 miles of underground gas mains. In addition, our real estate subsidiary, Unitil Realty, owns our corporate headquarters building and the 12 acres of land on which it is located.

Unitil Energy owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. Unitil Energy's 29 electric distribution substations, including one 5,000 kilovolt ampere and one 10,500 kilovolt ampere kVA mobile substation, constitute 219,037 kVA of capacity, which excludes capacity of spare transformers, for the transformation of electric power from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by Unitil Energy or land occupied by Unitil Energy pursuant to perpetual easements.

Unitil Energy has a total of approximately 1,617 pole miles of local transmission and distribution overhead electric lines and a total of 416 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Unitil Energy without objection by the owners. In the case of certain distribution lines, Unitil Energy owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

The physical utility properties of Unitil Energy, with certain exceptions, and its franchises are subject to its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of Unitil Energy are outstanding.

Fitchburg's electric properties consist principally of 560 pole miles of local transmission and distribution overhead electric lines, 180 conduit bank miles of underground electric distribution lines and 19 transmission and distribution stations (including two mobile electric substations). The capacity of these substations totals 443,150 kVA, which excludes capacity of spare transformers.

Fitchburg owns a LPG plant and a LNG plant, both of which are located on land owned by Fitchburg. Fitchburg also has 263 miles of underground steel, cast iron and plastic gas mains.

Fitchburg's electric substations, with minor exceptions, are located on land owned by Fitchburg or occupied by Fitchburg pursuant to perpetual easements. Fitchburg's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Fitchburg without objection by the owners. Fitchburg leases its distribution operations center located in Fitchburg, Massachusetts.

Northern Utilities' distribution system is comprised of 956 miles of gas mains and 38,692 service pipes. The gas mains are primarily made up of polyethylene plastic (65%), coated and wrapped cathodically protected steel (22%), cast/wrought iron (8%), and unprotected bare and coated steel (5%).

Northern Utilities' New Hampshire division serving 21 communities has 485 miles of distribution gas mains and 19,468 service pipes. Northern Utilities' Maine division serving 23 communities has 471 miles of distribution and 19,224 service pipes. Northern Utilities also owns a liquid propane gas plant on land owned by Northern Utilities.

Granite State is a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline located in Maine and New Hampshire.

The Company believes that its facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the December 2008 Ice Storm. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's common stock is listed on the New York Stock Exchange under the symbol "UTL". As of December 31, 2009, there were 1,644 shareholders of record.

Common Stock Data

Dividends per Common Share	2009	2008
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2009		2008	
Price Range of Common Stock	High/Ask	Low/Bid	High/Ask	Low/Bid
1st Quarter	**$20.75**	**$17.93**	$29.00	$25.75
2nd Quarter	**$22.79**	**$19.05**	$28.60	$26.41
3rd Quarter	**$23.20**	**$20.53**	$27.94	$25.46
4th Quarter	**$23.46**	**$19.55**	$26.60	$19.50

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

Equity Compensation Plan Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
Restricted Stock Plan (1)	—	N/A	62,318
Equity compensation plans not approved by security holders			
1998 Option Plan (2)	63,500	$28.90	—
Total	63,500	$28.90	62,318

NOTES: (also see Note 3 to the accompanying Consolidated Financial Statements)

(1) The Restricted Stock Plan (the Plan) was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006; 9,020 shares of restricted stock were awarded to Plan participants in February 2007; 15,540 shares of restricted stock were awarded to Plan participants in February 2008; 32,260 shares of restricted stock were awarded to Plan participants in February 2009. 12,520 shares of restricted stock were awarded to Plan participants in February 2010.

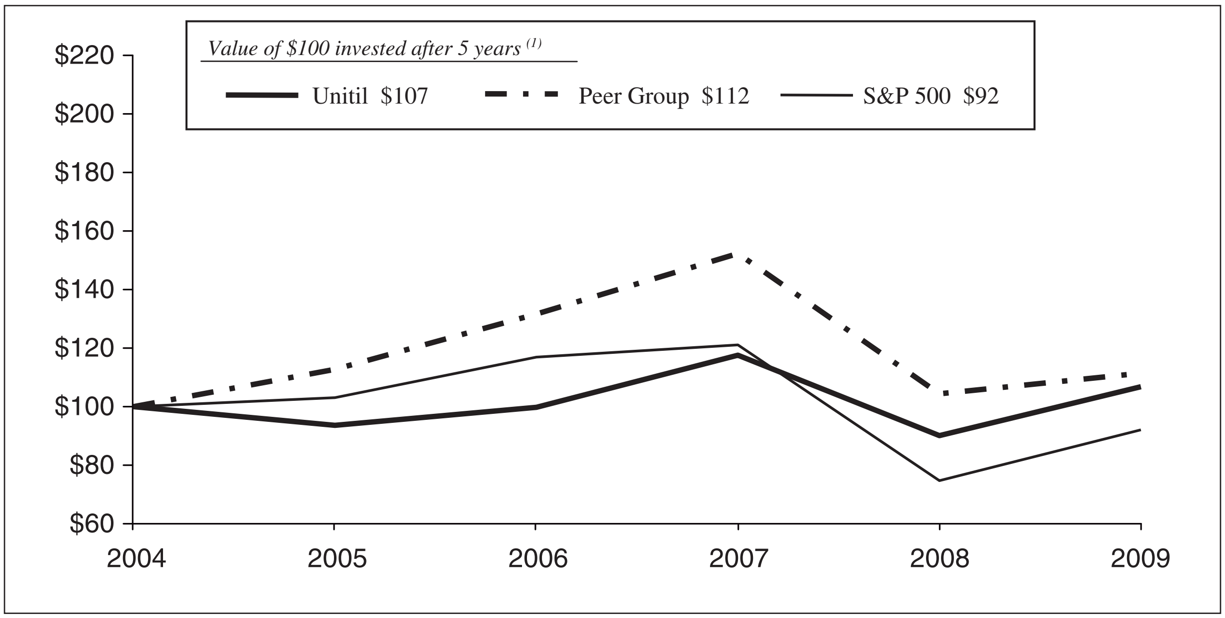
(2) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange (the exchange upon which the Company was then listed) rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of

Directors terminated the 1998 Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the 1998 Option Plan were deregistered with the Securities and Exchange Commission. The 1998 Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the 1998 Option Plan. No further grants of options will be made thereunder.

Stock Performance Graph

The following graph compares Unitil's cumulative stockholder return since December 31, 2004 with the Peer Group index, comprised of the S&P Utility Index, and the S&P 500 index. The graph assumes that the value of the investment in the Company's common stock and each index (including reinvestment of dividends) was $100 on December 31, 2004.

Comparative Five-Year Total Returns



NOTES:

(1) The graph above assumes $100 invested on December 31, 2004, in each category and the reinvestment of all dividends during the five-year period. The Peer Group is comprised of the S&P Utility Index.

Unregistered Sales of Equity Securities and Uses of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2009.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 26, 2009, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases; however, the trading plan will terminate when $83,000 in value of shares have been purchased or, if sooner, on March 26, 2010.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
10/1/09 – 10/31/09	—	—	—
11/1/09 – 11/30/09	—	—	—
12/1/09 – 12/31/09	2,781	$21.57	2,781
Total	2,781	$21.57	2,781

Item 6. Selected Financial Data

For the Years Ended December 31,	2009	2008	2007	2006	2005
(all data in millions except shares, % and per share data) [1]					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 367.0**	$ 288.2	$ 262.9	$ 260.9	$ 232.1
Operating Income	**26.1**	20.5	18.5	15.8	15.5
Other Non-operating Expense (Income)	**0.3**	0.3	0.2	—	0.1
Income Before Interest Expense, net	**25.8**	20.2	18.3	15.8	15.4
Interest Expense, net	**15.8**	10.5	9.6	7.8	6.8
Net Income	**10.0**	9.7	8.7	8.0	8.6
Dividends on Preferred Stock	**0.1**	0.1	0.1	0.1	0.2
Earnings Applicable to Common Shareholders	**$ 9.9**	$ 9.6	$ 8.6	$ 7.9	$ 8.4
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 682.7**	$ 641.4	$ 380.5	$ 353.0	$ 325.0
Total Assets	**$ 725.2**	$ 733.2	$ 474.6	$ 483.4	$ 450.1
Capitalization:					
Common Stock Equity	**$ 193.1**	$ 139.5	$ 100.4	$ 97.8	$ 96.3
Preferred Stock	**2.0**	2.0	2.1	2.1	2.3
Long-Term Debt, less current portion	**248.9**	249.3	159.6	140.0	125.4
Total Capitalization	**$ 444.0**	$ 390.8	$ 262.1	$ 239.9	$ 224.0
Current Portion of Long-Term Debt	**$ 0.4**	$ 0.4	$ 0.4	$ 0.3	$ 0.3
Short-term Debt	**$ 64.5**	$ 74.1	$ 18.8	$ 26.0	$ 18.7
Capital Structure Ratios:					
Common Stock Equity	**43%**	36%	38%	41%	43%
Preferred Stock	**1%**	1%	1%	1%	1%
Long-Term Debt	**56%**	63%	61%	58%	56%
Earnings Per Share Data:					
Earnings Per Average Share	**$ 1.03**	$ 1.65	$ 1.52	$ 1.41	$ 1.51
Common Stock Data:					
Shares of Common Stock—(Average Outstanding, 000's)	**9,647**	5,830	5,672	5,612	5,568
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.83**	$ 17.90	$ 17.50	$ 17.30	$ 17.21
Electric and Gas Sales:					
Electric Distribution Sales (Millions kWh)	**1,618.8**	1,695.9	1,743.0	1,751.5	1,790.4
Firm Natural Gas Distribution Sales (Millions Therms)	**178.7**	47.2	28.4	26.4	24.3

(1) As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

OVERVIEW

Unitil is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy, which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,500 electric customers and 70,000 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite State, a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in Net Utility Plant of $449.7 million at December 31, 2009. Unitil's total revenue was $367.0 million in 2009, which includes revenue to recover the approved cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not affected by changes in the cost of purchased electricity and natural gas. Earnings from Unitil's utility operations are derived from the return on investment in the three distribution utilities and Granite.

Unitil also conducts non-regulated operations principally through Usource, which is wholly-owned by Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Usource's total revenues were $4.3 million in 2009. The Company's other subsidiaries include Unitil Service, which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, and Unitil Realty, which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- The Company's ability to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Recovery of deferred major storm costs;
- Recovery of energy commodity costs;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions that could have an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of our counterparty obligations, including those of our insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A Risk Factors.

ACCOUNTING CODIFICATION

In June 2009, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 168), a replacement of SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles". SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States (U.S. GAAP). SFAS No. 168 is effective for financial statements for interim and annual periods ending after September 15, 2009. SFAS No. 168 establishes the FASB Accounting Standards Codification (FASB Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with U.S. GAAP. The purpose of the FASB Codification is to simplify U.S. GAAP, without change, by consolidating the numerous accounting rules into logically organized topics. The Company has adopted SFAS No. 168 and therefore all references by the Company to authoritative accounting principles recognized by the FASB reflect the FASB Codification.

RESULTS OF OPERATIONS

The following discussion of the Company's financial condition and results of operations should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report.

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company's results will reflect the seasonal nature of the natural gas business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Net Income and EPS Overview

2009 Compared to 2008—The Company's Earnings Applicable to Common Shareholders was $1.2 million, or $0.11 per common share, for the fourth quarter of 2009 compared to $3.2 million, or $0.53 per common share, for the fourth quarter of 2008. The Company also reported earnings of $9.9 million for the full year period of 2009, compared to $9.6 million for 2008. Earnings per common share were $1.03 for 2009, ($0.62) per share lower than last year's earnings of $1.65. The lower earnings per common share in the fourth quarter and full year period of 2009 primarily reflect higher regulatory and legal expenses in 2009 associated with the devastating ice storm that struck New England in December 2008 and a significant non-recurring regulatory matter.

In 2009 the Company recognized professional fees of approximately $3.0 million related to regulatory and legal matters concerning the Company's preparation and response to the devastating ice storm that struck the New England region on December 11 and 12, 2008. In the fourth quarter of 2009, the Company also recognized a non-recurring accounting charge for a regulatory order that required Fitchburg Gas and Electric Light Company, the Company's Massachusetts combination gas and electric operating utility, to refund $4.9 million of natural gas supply costs, including carrying charges. Excluding these one-time charges, the Company's Earnings Applicable to Common Shareholders was $5.1 million, or $0.47 per common share, for the fourth quarter of 2009 and $15.1 million, or $1.57 per share, for the full year ended December 31, 2009.

In addition to the one-time charges, earnings in 2009 reflect higher gas utility sales margins offset by higher operating, depreciation and interest costs. Natural gas sales margin increased $35.1 million in 2009 compared to 2008, reflecting the contribution to natural gas sales by Northern Utilities and Granite State. Natural gas sales margin also includes the unfavorable effect of a refund of $4.9 million of natural gas supply costs recorded in the fourth quarter of 2009. Electric sales margin increased $0.4 million in 2009 compared to 2008, reflecting higher electric rates offset by lower sales. Total electric kilowatt-hour (kWh) sales decreased 4.5% in 2009 compared to 2008, reflecting lower average usage by customers due to the continued economic slowdown and milder summer weather in 2009. Average summer temperatures in the Company's electric service territories, as measured by cooling degree days, were 31% cooler in 2009 compared to the same period in 2008 and were 26% cooler than normal. Unitil paid common dividends of $1.38 in 2009.

Total Operation & Maintenance (O&M) expenses increased $17.2 million, or 62.5%, in 2009 compared to 2008. The inclusion of Northern Utilities and Granite State for the full year in 2009 accounted for $8.8 million of the increase. In addition, higher compensation and retiree and employee benefit expenses of $2.2 million and net other utility operating costs of $0.4 million contributed to the increase in O&M expenses year over year. As discussed above, in 2009 the Company expensed professional fees of approximately $3.0 million related to regulatory and legal matters concerning the December 2008 Ice Storm. The increase in O&M expenses in 2009 over 2008 also reflects lower O&M recorded in 2008 due to the receipt of a $2.8 million insurance settlement in that year.

Depreciation, Amortization, Taxes and Other expenses increased $13.2 million in 2009 compared to 2008. The increase is largely due to the inclusion of Northern Utilities and Granite State for the full year in 2009, higher depreciation on normal utility plant additions and higher income taxes on higher pre-tax earnings in 2009.

Interest Expense, Net increased $5.3 million in 2009 compared to 2008. The increase is due to the issuance of $90 million of long-term notes issued by Northern Utilities and Granite State in December 2008 to partially finance the acquisition and higher average borrowings during 2009, partially offset by increases in interest income on regulatory assets and Allowance for Funds Used During Construction (AFUDC) in 2009.

The Company's non-regulated energy brokering and advisory services business, Usource, achieved sales margins of $4.3 million in 2009, and contributed $1.6 million to consolidated Earnings, or $0.16 per share for the year compared to earnings of $0.3 million, or $0.06 per share in 2008.

On December 11 and 12, 2008, a severe ice storm struck the New England region, creating extended power outages for many residents of Massachusetts and New Hampshire, including Unitil's electric customers in New Hampshire and the greater Fitchburg, Massachusetts service territory. As discussed above, the Company has received approval from the MDPU and the NHPUC to defer storm restoration costs associated with the repair of damages to its electric distribution system caused by the December 2008 Ice Storm and to request recovery for these costs in Fitchburg's and Unitil Energy's next rate cases. The Company has accrued and deferred, excluding capital construction expenditures, approximately $14.6 million in costs, including carrying charges, for the repair and replacement of electric distribution systems damaged during the storm. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations.

In 2009, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January 2010 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

Between December 2008 and June 2009, the Company sold 4,970,000 shares of its common stock at a price of $20.00 per share in registered public offerings. The Company used the net proceeds of $93.1 million from these offerings to finance the acquisition of Northern Utilities and Granite State and for capital contributions to Unitil's other distribution utilities and the repayment of short-term debt. Overall, the results of operations and net income are reflected over a higher number of average shares outstanding year over year.

2008 Compared to 2007—The Company's Earnings Applicable to Common Shareholders was $9.6 million for 2008, an increase of 12% over 2007 Earnings of $8.6 million. Earnings per common share were $1.65 for 2008, $0.13 per share higher than last year. Earnings in 2008 reflect the acquisitions, on December 1, 2008, of Northern Utilities and Granite State. The acquisitions have increased the share of the company's operating results attributable to gas operations, which have a higher proportion of annual gas sales margin during the winter months.

A more detailed discussion of the Company's 2009 and 2008 results of operations and a year-to-year comparison of changes in financial position are presented below.

Gas Sales, Revenues and Margin

Therm Sales—Overall, Unitil's total therm sales of natural gas increased 278.6% in 2009 compared to 2008, reflecting the contribution to sales by Northern Utilities. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas decreased 0.7% in 2009 compared to 2008, reflecting a decrease of 2.0% in sales to residential customers and flat year over year sales to C&I customers. The decrease in sales to residential customers reflects lower average usage by our customers, due to a slowing economy and energy conservation, partially offset by a colder winter heating season in the first quarter of 2009.

Overall, Unitil's total therm sales of natural gas increased 66.2% in 2008 compared to 2007. Excluding the contribution of the acquisition of Northern Utilities, total therm sales of natural gas increased 1.1% in 2008 compared to 2007, reflecting a decrease of 2.0% in sales to residential customers offset by an increase of 2.7% in sales to C&I customers. The lower sales to residential customers in 2008 reflects a milder winter heating season and lower average usage by our customers reflecting a slowing economy and energy conservation. The increase in gas sales to C&I customers in 2008 reflects increased usage of natural gas in those customers' production operations.

The following table details total therm sales for the last three years, by major customer class:

Therm Sales (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	2008	2007	Change	Change %	Change	Change %
Residential	**36.7**	13.3	10.2	23.4	175.9%	3.1	30.4%
Commercial / Industrial	**142.0**	33.9	18.2	108.1	318.9%	15.7	86.3%
Total	**178.7**	47.2	28.4	131.5	278.6%	18.8	66.2%

Gas Operating Revenues and Sales Margin—The following table details Total Gas Operating Revenue and Gas Sales Margin for the last three years by major customer class:

Gas Operating Revenues and Gas Sales Margin (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	2008	2007	$ Change	% Change (1)	$ Change	% Change (1)
Gas Operating Revenue:							
Residential	**$ 62.0**	$27.5	$18.8	$34.5	60.6%	$ 8.7	25.4%
Commercial / Industrial	**90.8**	29.4	15.4	61.4	107.9%	14.0	41.0%
Total Gas Operating Revenue	**$152.8**	$56.9	$34.2	$95.9	168.5%	$22.7	66.4%
Cost of Gas Sales:							
Purchased Gas	**$ 96.4**	$37.3	$21.3	$59.1	103.9%	$16.0	46.8%
Conservation & Load Management	**1.9**	0.2	0.2	1.7	2.9%	—	—
Total Cost of Gas Sales	**$ 98.3**	$37.5	$21.5	$60.8	106.8%	$16.0	46.8%
Gas Sales Margin	**$ 54.5**	$19.4	$12.7	$35.1	61.7%	$ 6.7	19.6%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $95.9 million, or 168.5%, in 2009 compared to 2008, reflecting the inclusion of Northern Utilities and Granite State for the full year in 2009. Total Gas Operating Revenues include the recovery of the approved cost of sales, which are recorded as Purchased Gas and Conservation and Load Management (C&LM) in Operating Expenses. The increase in Total Gas Operating Revenues in 2009 reflects higher Purchased Gas costs of $59.1 million, higher C&LM revenues of $1.7 million and higher sales margin of $35.1 million.

Purchased Gas and C&LM revenues increased $60.8 million, or 106.8%, of Total Gas Operating Revenues in 2009 compared to 2008, reflecting the inclusion of Northern Utilities and Granite State for the full year in 2009 and the $4.9 million refund of natural gas supply costs recorded in the fourth quarter of 2009. Purchased Gas revenues include the recovery of the approved cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $35.1 million in 2009 compared to 2008, reflecting the contribution to natural gas sales by Northern Utilities and Granite State. Natural gas sales margin also includes the unfavorable effect of a refund of $4.9 million of natural gas supply costs recorded in the fourth quarter of 2009.

Total Gas Operating Revenues increased $22.7 million, or 66.4%, in 2008 compared to 2007, largely reflecting the acquisition of Northern Utilities and Granite State on December 1, 2008 and the 1.1% increase in gas sales, net of the effect of the acquisitions, and higher rates implemented in November 2007. The increase in Total Gas Operating Revenues in 2008 reflects higher Purchased Gas costs of $16.0 million and higher sales margin of $6.7 million.

Natural gas sales margin increased $6.7 million in 2008 compared to 2007. This increase reflects $5.4 million of gas sales margin from Northern Utilities and Granite State and an additional increase of $1.3 million in gas sales margin reflecting higher rates implemented in November 2007 and higher sales to C&I customers.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales—Unitil's total electric kWh sales decreased 4.5% in 2009 compared to 2008. Electric kWh sales to residential customers and C&I customers decreased 2.2% and 6.1%, respectively, in 2009 compared to 2008. The lower electric kWh sales in 2009 compared to 2008 reflect lower average usage by our customers due to the continued regional economic slowdown and milder summer weather in 2009. Average summer temperatures in the Company's electric service territories, as measured by cooling degree days, were 31% cooler in 2009 compared to the same period in 2008 and were 26% cooler than normal.

Unitil's total electric kWh sales decreased 2.7% in 2008 compared to 2007. Electric kWh sales to residential customers and C&I customers decreased 2.2% and 3.0%, respectively, in 2008 compared to 2007. The lower electric kWh sales in 2008 compared to 2007 were driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	**2008**	**2007**	**Change kWh**	**Change %**	**Change kWh**	**Change %**
Residential	**645.9**	660.2	674.8	(14.3)	(2.2%)	(14.6)	(2.2%)
Commercial / Industrial	**972.9**	1,035.7	1068.2	(62.8)	(6.1%)	(32.5)	(3.0%)
Total	**1,618.8**	1,695.9	1,743.0	(77.1)	(4.5%)	(47.1)	(2.7%)

Electric Operating Revenues and Sales Margin—The following table details Total Electric Operating Revenue and Electric Sales Margin for the last three years by major customer class:

Electric Operating Revenues and Electric Sales Margin (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	**2008**	**2007**	**$ Change**	**% Change (1)**	**$ Change**	**% Change (1)**
Electric Operating Revenue:							
Residential	**$108.9**	$114.5	$114.7	$ (5.6)	(2.5%)	$(0.2)	(0.1%)
Commercial / Industrial	**101.0**	113.0	110.3	(12.0)	(5.2%)	2.7	1.2%
Total Electric Operating Revenue	**$209.9**	$227.5	$225.0	$(17.6)	(7.7%)	$ 2.5	1.1%
Cost of Electric Sales:							
Purchased Electricity	**$151.6**	$170.1	$165.4	$(18.5)	(8.1%)	$ 4.7	2.1%
Conservation & Load Management	**3.1**	2.6	3.4	0.5	0.2%	(0.8)	(0.4%)
Total Cost of Electric Sales	**$154.7**	$172.7	$168.8	$(18.0)	(7.9%)	$ 3.9	1.7%
Electric Sales Margin	**$ 55.2**	$ 54.8	$ 56.2	$ 0.4	0.2%	$(1.4)	(0.6%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues decreased by $17.6 million, or 7.7%, in 2009 compared to 2008. Total Electric Operating Revenues include the recovery of approved costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The net decrease in Total Electric Operating Revenues in 2009 reflects lower Purchased Electricity costs of $18.5 million offset by higher C&LM revenues of $0.5 million and higher sales margin of $0.4 million.

Purchased Electricity and C&LM revenues decreased $18.0 million, or 7.9%, of Total Electric Operating Revenues in 2009 compared to 2008, primarily reflecting lower sales volumes and lower electric commodity prices, partially offset by higher spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the approved cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $0.4 million in 2009 compared to 2008. The increase in electric sales margin reflects higher rates offset by lower sales volumes. Total electric sales decreased 4.5% in 2009 compared to 2008, reflecting lower average usage by our customers due to the continued economic slowdown and milder summer weather in 2009.

Total Electric Operating Revenues increased by $2.5 million, or 1.1%, in 2008 compared to 2007. The net increase in Total Electric Operating Revenues in 2008 reflects higher Purchased Electricity costs of $4.7 million offset by lower C&LM revenues of $0.8 million and lower sales margin of $1.4 million.

Electric sales margin decreased $1.4 million in 2008 compared to 2007. The decrease in electric sales margin primarily reflects lower sales volumes, partially offset by higher electric base rates implemented in March of 2008. Total electric sales decreased 2.7% in 2008 compared to 2007 driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

Operating Revenue—Other

Total Other Revenue increased $0.5 million in 2009 compared to 2008 and $0.1 million in 2008 compared to 2007. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	2008	2007	$ Change	% Change	$ Change	% Change
Usource	**$4.3**	$3.8	$3.7	$0.5	13.2%	$0.1	2.7%
Total Other Revenue	**$4.3**	$3.8	$3.7	$0.5	13.2%	$0.1	2.7%

Operating Expenses

Purchased Gas—Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $59.1 million, or 158.4%, in 2009 compared to 2008. This increase primarily reflects the inclusion of Northern Utilities for the full year in 2009. The Company recovers the approved costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in approved expenses do not affect earnings.

In 2008, Purchased Gas increased $16.0 million, or 75.1%, compared to 2007. The increase in Purchased Gas largely reflects the acquisition of Northern Utilities and Granite State on December 1, 2008. In addition to the increase in Purchased Gas due to the acquisitions, Purchased Gas increased $1.5 million, or 7.0%, in 2008 compared to 2007 reflecting higher natural gas commodity prices and higher sales to C&I customers.

Purchased Electricity—Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity decreased $18.5 million, or 10.9%, in 2009 compared to 2008. This decrease reflects lower sales volumes and lower electric commodity prices. The Company recovers the approved costs of Purchased Electricity in its rates at cost and therefore changes in approved expenses do not affect earnings.

In 2008, Purchased Electricity expenses increased $4.7 million, or 2.8%, compared to 2007, reflecting higher electric commodity prices partially offset by lower sales volumes.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. Total O&M expenses increased $17.2 million, or 62.5%, in 2009 compared to 2008. The inclusion of Northern Utilities and Granite State for the full year in 2009 accounted for $8.8 million of the increase. In addition, higher compensation and retiree and employee benefit expenses of $2.2 million and net other utility operating costs of $0.4 million contributed to the increase in O&M expenses year over year. As discussed above, in 2009 the Company expensed professional fees of approximately $3.0 million related to regulatory and legal matters concerning the December 2008 Ice Storm. The increase in O&M expenses in 2009 over 2008 also reflects lower O&M recorded in 2008 due to the receipt of a $2.8 million insurance settlement in that year.

In 2008, total O&M expense increased $1.3 million, or 5.0%, compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.9 million of the increase. In addition, the increase in O&M expenses reflects higher employee and retiree compensation and benefit expenses of $2.7 million, including increased employee benefits of $1.4 million, driven primarily by higher medical claims in 2008 and higher employee benefits related to staffing increases, and higher salaries and compensation of $1.3 million, due to normal annual increases and staffing additions. Also contributing to the increase in O&M expenses were higher utility operating costs of $0.3 million and higher bad debt expenses of $0.3 million, partially offset by a reduction of $2.8 million from the proceeds of an insurance settlement and lower professional fees of $0.1 million.

Conservation & Load Management—C&LM expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 60% of these costs are related to electric operations and 40% to gas operations.

Total C&LM expenses increased by $2.2 million, in 2009 compared to 2008. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total C&LM expenses decreased by $0.8 million in 2008 compared to 2007.

Depreciation and Amortization—Depreciation and Amortization expense increased $8.3 million, or 43.5% in 2009 compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009 and higher depreciation on normal utility plant additions.

In 2008, Depreciation and Amortization expense increased $1.3 million, or 7.3%, compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.6 million of the increase. In addition, the increase in Depreciation and Amortization expense reflects higher depreciation on normal utility plant additions.

Local Property and Other Taxes—Local Property and Other Taxes increased by $4.1 million, or 63.1%, in 2009 compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009, and higher local property tax rates on higher levels of utility plant in service.

In 2008, Local Property and Other Taxes increased by $0.9 million, or 16.1%, compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.3 million of the increase. In addition, the increase in Local Property and Other Taxes reflects higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes—Federal and State Income Taxes increased by $0.8 million in 2009 compared to 2008 due to higher pre-tax operating income in 2009 compared to 2008 (See Note 8 to the accompanying Consolidated Financial Statements).

Federal and State Income Taxes decreased by $0.1 million in 2008 compared to 2007 due to a lower effective tax rate year over year due to the recognition of higher permanent book/tax differences partially offset by higher pre-tax operating income in 2008 compared to 2007.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) was flat in 2009 compared to 2008.

Other Non-operating Expenses (Income) increased by $0.1 million in 2008 compared to 2007. This change reflects an adjustment of $0.1 million in conjunction with the Company's electric base distribution rate increase in Massachusetts which was implemented in March of 2008.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated (See Note 4 to the accompanying Consolidated Financial Statements).

Interest Expense, net increased $5.3 million in 2009 compared to 2008. The increase is primarily due to the issuance of $90 million of long-term notes issued by Northern Utilities and Granite State in December 2008 to partially finance the acquisition and higher average borrowings during 2009, partially offset by increases in interest income on regulatory assets and AFUDC in 2009.

In 2008, Interest Expense, net, rose by $0.9 million compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.3 million of the increase. The increase associated with the acquisitions is due to $0.5 million of interest expense from the issuance of long-term notes by Northern Utilities and Granite State in December 2008, partially offset by interest income on regulatory mechanisms. In addition to the increase related to the acquisitions, the remaining $0.6 million increase in Interest Expense, net reflects higher debt outstanding and lower interest earned on regulatory assets compared to the prior period.

LIQUIDITY, COMMITMENTS AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

On December 18, 2009, both Unitil Energy and Northern Utilities priced long-term financings scheduled to close in the first quarter of 2010:

(i) Unitil Energy priced $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds were priced at a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Unitil Energy anticipates closing this long-term financing in March 2010.

(ii) Northern Utilities priced $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes were priced at a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Northern Utilities anticipates closing this long-term financing in March 2010.

The Unitil Energy and Northern Utilities securities offered will not be, and have not been, registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

The Company, along with its subsidiaries, are individually and collectively members of the Unitil Cash Pool (the Cash Pool). The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool allows for an efficient exchange of cash among the Company and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on actual interest costs from lenders under the Company's revolving credit facility. At December 31, 2009 and 2008, all of the Company's subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

As of December 31, 2009 and 2008, the Company had $64.5 million and $35.0 million, respectively, in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of December 31, 2009 and 2008, the Company was in compliance with the financial covenants contained in the revolving credit facility agreement.

The continued availability of various methods of financing, as well as the choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of earnings, cash flows, financial position; and the competitive pricing offered by financing sources.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2009.

		Payments Due by Period			
Contractual Obligations (millions) as of December 31, 2009	**Total**	**2010**	**2011-2012**	**2013-2014**	**2015 & Beyond**
Long-term Debt Obligations	$249.3	$ 0.4	$ 1.0	$ 3.0	$244.9
Interest on Long-term Debt Obligations	284.0	17.9	35.7	35.6	194.8
Gas Supply Contracts [1]	190.5	61.6	58.0	47.6	23.3
Power Supply Contract Obligations	34.7	13.0	17.8	1.8	2.1
Other	5.5	1.7	2.5	0.8	0.5
Total Contractual Cash Obligations	$764.0	$94.6	$115.0	$88.8	$465.6

(1) Primarily reflects demand charges associated with natural gas transportation contracts.

The Company and its subsidiaries have material energy supply commitments that are discussed in Note 6 to the accompanying Consolidated Financial Statements. Cash outlays for the purchase of electricity and natural gas to serve customers are subject to reconciling recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over-collected cash over subsequent periods of less than a year.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2009, there were approximately $30.5 million of guarantees outstanding and the longest term guarantee extends through December 31, 2010. Of this amount, $8.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed below.

Northern enters into asset management agreements under which Northern releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $10.0 million and $31.8 million outstanding at December 31, 2009 and December 31, 2008, respectively, related to these asset management agreements.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.3 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Benefit Plan Funding

The Company, along with its subsidiaries, made cash contributions to its Pension Plan in the amount of $4.2 million and $2.8 million in 2009 and 2008, respectively. The Company, along with its subsidiaries (other than Northern Utilities and Granite State), contributed $2.8 million and $2.7 million to Voluntary Employee Benefit Trusts (VEBT) in 2009 and 2008, respectively. The Company expects to contribute approximately $4.0 million and $2.8 million, respectively, to fund its Pension and PBOP Plans in 2010. The Company, along with its subsidiaries, expects to continue to make contributions to its Pension Plan and the VEBTs in future years in amounts consistent with the amounts recovered in the distribution utilities' rates for these other postretirement benefit costs. (See Note 9 to the accompanying Consolidated Financial Statements.)

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements. (See Note 4 to the accompanying Consolidated Financial Statements.)

Cash Flows

On December 1, 2008, the Company acquired Northern Utilities and Granite State. Cash flow results for 2009 include a full-year of activity for the acquired companies, while cash flow results for 2008 include only one month of activity for the acquired companies. Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for 2009 and 2008.

(millions)	**2009**	**2008**
Cash Provided by Operating Activities	**$50.9**	$47.3

Cash Provided by Operating Activities—Cash Provided by Operating Activities was $50.9 million in 2009, an increase of $3.6 million over the comparable period in 2008. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes, was $44.5 million in 2009 compared to $36.2 million in 2008, representing an increase of $8.4 million. Working capital changes in Current Assets and Liabilities resulted in a $29.4 million source of cash in 2009, compared to a $0.7 million use of cash in 2008, representing an increased source of cash of $30.1 million primarily due to a reduction in Gas Inventory of 17.3 million and a decrease in Accrued Revenue of $12.9 million. Deferred Regulatory and Other Charges resulted in a $24.6 million use of cash, compared to a $2.6 million source of cash in

2008, primarily related to the funding in 2009 of non-recurring Deferred Regulatory Charges related to the December 2008 Ice Storm of $14.0 million. All other Operating Activities resulted in a source of cash of $1.6 million in 2009, compared to a source of cash of $9.2 million in 2008.

(millions)	2009	2008
Cash (Used in) Investing Activities	**$(65.6)**	$(238.2)

Cash (Used in) Investing Activities—Cash Used in Investing Activities was $65.6 million for 2009 compared to $238.2 million used in 2008. Northern Utilities and Granite State acquisition costs were $6.9 million in 2009 compared to $209.9 million in 2008. Capital expenditures for property, plant and equipment additions were $58.7 million in 2009 compared to $28.3 million in 2008, representing an increased use of cash of $30.4 million primarily due to the acquisition of Northern Utilities and Granite State. Cash Used in Investing Activities in 2008 included $209.9 million for the Company's acquisition of Northern Utilities and Granite State on December 1, 2008. Capital expenditures are projected to be approximately $60 million in 2010, reflecting normal electric and gas utility system additions.

(millions)	2009	2008
Cash Provided by Financing Activities	**$10.9**	$197.8

Cash Provided by Financing Activities—Cash Provided by Financing Activities was $10.9 million in 2009 compared to $197.8 million in 2008. In 2009, sources of cash from financing activities included proceeds from the issuance of common stock of $56.4 million, and uses of cash included a decrease in Gas Inventory Financing of $21.8 million, regular quarterly dividend payments on common and preferred stock of $13.2 million, the repayment of short-term debt of $9.6 million and the scheduled repayment of long-term debt of $0.4 million. Cash Provided by Financing Activities in 2008 primarily reflects the financing activity related to the Company's acquisition of Northern Utilities and Granite State on December 1, 2008.

FINANCIAL COVENANTS AND RESTRICTIONS

The agreements under which the Company's and its subsidiaries' long-term debt were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations and covenants restricting the ability to (i) pay dividends, (ii) incur indebtedness and liens, (iii) merge or consolidate with another entity or (iv) sell, lease or otherwise dispose of all or substantially all assets. (See Note 4 to the accompanying Consolidated Financial Statements.)

The long-term debt and preferred stock of Unitil, Unitil Energy, Fitchburg, Northern Utilities, Granite State and Unitil Realty are privately held, and the Company does not issue commercial paper. For these reasons, the debt securities of Unitil and its subsidiaries are not publicly rated.

The Company's revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter.

The Company and its subsidiaries are currently in compliance with all such covenants in these debt instruments.

DIVIDENDS

Unitil's annualized common dividend was $1.38 per common share in 2009, 2008 and 2007. Unitil's dividend policy is reviewed periodically by the Board of Directors. Unitil has maintained an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2010 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

LEGAL PROCEEDINGS

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the December 2008 Ice Storm. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company continues to believe the suit is without merit, and will defend itself vigorously.

REGULATORY MATTERS

Overview (Unitil Energy, Fitchburg, and Northern Utilities): Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territory at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next two to four years, is $63.0 million as of December 31, 2009 including $17.7 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans. See Note 6 for additional information on these filings.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Unitil was able to restore power to over 80 percent of its customers by day seven, and its final customers, including those with individual service problems, were restored in Massachusetts by December 24, 2008. As a result of the ice storm, the Company has spent approximately $23 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.3 million related to capital construction and $14.6 million, including carrying charges, which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million in 2009 for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

On January 7, 2009, the MDPU opened an investigation into the preparation and response of the Massachusetts electric distribution companies to the December 2008 Ice Storm. Evidentiary hearings before the MDPU concerning Fitchburg's storm response were held in May, 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service. As a result, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices to address: Unitil's strategic planning processes; its staffing decisions to the extent to which they affect Fitchburg; its management and control of Fitchburg, including resource allocation decisions made among Unitil's three subsidiary companies; and customer relations. The order also directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

On July 28, 2009, Fitchburg filed with the MDPU a petition for approval to defer and record as a regulatory asset approximately $11.5 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. On December 30, 2009, the MDPU approved the request. The order of approval stated that it made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. Fitchburg anticipates filing its next rate case during the second quarter of 2010. As of December 31, 2009, Fitchburg has deferred approximately $12.3 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On August 26, 2009, Unitil Energy filed a petition with the NHPUC requesting an accounting order authorizing Unitil Energy to record as a regulatory asset approximately $2 million in expenses associated with network damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's next base rate case. On November 9, 2009, the NHPUC granted the requested accounting order, clarifying that such issues as the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are issues that will be deferred to Unitil Energy's next rate case. Unitil Energy anticipates filing its next rate case during the second quarter of 2010. As of December 31, 2009, Unitil Energy has deferred approximately $2.3 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On December 3, 2009, the NHPUC issued its final report regarding its 'after action' review of the December 2008 Ice Storm. The after action review was a non-docketed investigation by the NHPUC of utility emergency preparedness and response. The report stated that the NHPUC will commence an adjudicative proceeding to examine the reasonableness of the timing of Unitil's response to the December 2008 Ice Storm, the priorities of its restorations and the allocation of its resources in New Hampshire and Massachusetts. On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. This matter remains pending.

Unitil Energy: On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On January 16, 2009, the NHPUC issued its decision in this matter, concluding that such rate mechanisms should only be implemented on a company-by-company basis in the context of an examination of company-specific costs and revenues, service territory, customer mix and rate base investment. On March 23, 2009, the NHPUC denied a Motion for Rehearing of this matter.

In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009, Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources.

Fitchburg—Electric Operations: On November 25, 2009, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery is proposed through a Transition Charge Surcharge of $0.004 per kWh. Changes to the Pension / PBOP Adjustment and Residential Assistance Adjustment Factor were proposed in other proceedings. The rates were approved effective January 1, 2010, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2008 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting the items required by House Bill 4329.

Fitchburg—Gas Operations: Fitchburg provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current distribution rates were approved by the MDPU in 2007. Fitchburg's customers may purchase natural gas supplies from third-party vendors or purchase their natural gas from Fitchburg under regulated rates and tariffs. Fitchburg collects its natural gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On March 12, 2009, the MDPU opened an investigation into Fitchburg's gas procurement practices. On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

During the summer of 2009, Fitchburg operated its gas system entirely on local production from LNG for approximately three months due to construction on the lateral from Tennessee Gas Pipeline, which is the sole source of pipeline gas to Fitchburg. During this time Fitchburg provided gas LNG supply to all firm sales customers and also to the retail marketers for delivery to firm customers who have contracted for third-party supply. Fitchburg's management of this project was reviewed by the MDPU during its last Integrated Resource Plan proceeding, before the shutdown occurred. In its order, the MDPU stated it would investigate the costs associated with the shutdown in Fitchburg's March 2010 Cost of Gas Adjustment Clause filing when its actual costs will be reconciled with its projected costs.

Fitchburg—Other: On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, including company-specific rate cases. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012.

On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, and special tariffs to allow the net metering of customer-owned renewable generation. These matters, under review in separately designated dockets, remain pending, except for net metering tariffs which were approved by the MDPU effective December 1, 2009.

Northern Utilities: On December 1, 2008 Unitil completed the purchase of Northern Utilities from Bay State and Granite State from NiSource. Unopposed settlement agreements resolving all outstanding issues and recommending approval of the acquisition were approved by the NHPUC on October 10, 2008, and by the MPUC on November 5, 2008. Pursuant to its expanded authority over holding company mergers under the GC Act, the MDPU also reviewed the transaction and issued its approval on November 18, 2008.

The New Hampshire and Maine settlement agreements included the following provisions with respect to the accounting and rates of Northern Utilities:

- approval of Northern Utilities' accounting deferral and 10-year amortization of transaction costs and transition costs resulting from the Company's acquisition of Northern Utilities and the Company's agreement not to seek recovery of these costs, or the transaction or transition costs of any other utility subsidiary, in rates;
- agreement that synergy savings resulting from the acquisition of Northern Utilities will be retained by the Company until the next base rate change and then will flow to customers;
- agreement not to request a base rate change for Northern Utilities before November 1, 2010 unless (i) Northern Utilities' projected annual revenues are more than 8% below the level of total 2007 distribution revenues or (ii) the MPUC or NHPUC, as applicable, approves a plan to subject Granite State's rates to state regulation;

- agreement to allow Northern Utilities to recover prudently incurred integration costs for capitalized expenditures to build or upgrade systems or facilities required to independently operate Northern Utilities;
- agreement not to seek recovery in Northern Utilities' rates of any acquisition premium resulting from Unitil's acquisition of Northern Utilities and that any acquisition adjustment (positive or negative) shall be accounted for below the line for ratemaking purposes over a 10-year period;
- agreement to hold Northern Utilities' customers harmless for the elimination of historical accumulated deferred income tax liabilities resulting from its Internal Revenue Service Section 338(h)(10) election;
- agreement to use an imputed weighted cost of debt for ratemaking purposes until Northern Utilities' existing debt instruments would have matured; and
- agreement not to change Northern Utilities' existing depreciation rates for its Maine division until approved in the next general rate case.

The settlement agreements contained the following commitments related to Granite State:

- agreement to work collaboratively with the parties to the settlements to design and to conduct a comprehensive study of the issues and costs for modification of the physical, operational, regulatory, and corporate structure necessary for state regulation of Granite State and to provide a report within one year of the closing; and
- authorization for Northern Utilities to execute a firm service contract with Granite State for 100,000 Dekatherms (Dth) of capacity at Granite State's current recourse rate of $1.6666 / Dth for the period November 1, 2008 through October 31, 2010.

On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation (NOPVs) of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern's distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at December 31, 2009 was $2.3 million.

On June 27, 2008, the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in the Portland and Westbrook service areas. Northern Utilities anticipates filing testimony and a proposal for a replacement program with the MPUC by mid-February of 2010, and that proceedings will continue on this matter during the second and third quarters 2010.

See Note 6 to the accompanying Consolidated Financial Statements for additional information on Regulatory Matters.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former MGP site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows

Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800's through the mid 1900's. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

See Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES AND EMPLOYEE RELATIONS

As of December 31, 2009, the Company and its subsidiaries had 431 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2009, 156 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two agreements expire on May 31, 2010, one agreement expires on June 5, 2010 and one agreement expires on March 31, 2012. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with U.S. GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. In accordance with the FASB Codification, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The FASB Codification specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets". If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities".

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided in Note 1 thereto. The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements.

The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The FASB Codification requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2009 and 2008, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000 and $200,000, respectively, in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2009 and 2008, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $735,000 and $675,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $576,000 and $531,000, respectively. (See Note 9 to the accompanying Consolidated Financial Statements).

Income Taxes—Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes.

Depreciation—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2009, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to “Recently Issued Accounting Pronouncements” in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, “Summary of Significant Accounting Policies,” Note 8, “Income Taxes,” Note 5, “Energy Supply,” Note 9, “Benefit Plans,” and Note 6, “Commitment and Contingencies,” to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please also refer to Item 1A. “Risk Factors.”

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 3.4%, 3.8%, and 5.6% during 2009, 2008, and 2007, respectively.

MARKET RISK

Although Unitil’s three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the years ended December 31, 2009, 2008 and 2007. We also have audited Unitil Corporation and subsidiaries' internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unitil Corporation and subsidiaries as of December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Unitil Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in (COSO).

Caturano and Company, P.C.

Boston, Massachusetts
February 10, 2010

[THIS PAGE INTENTIONALLY LEFT BLANK]

CONSOLIDATED STATEMENTS OF EARNINGS

(Millions, except common shares and per share data)

Year Ended December 31,	2009	2008	2007
Operating Revenues:			
Gas	**$152.8**	$ 56.9	$ 34.2
Electric	**209.9**	227.5	225.0
Other	**4.3**	3.8	3.7
Total Operating Revenues	**367.0**	288.2	262.9
Operating Expenses:			
Purchased Gas	**96.4**	37.3	21.3
Purchased Electricity	**151.6**	170.1	165.4
Operation and Maintenance	**44.7**	27.5	26.2
Conservation & Load Management	**5.0**	2.8	3.6
Depreciation and Amortization	**27.4**	19.1	17.8
Provisions for Taxes:			
Local Property and Other	**10.6**	6.5	5.6
Federal and State Income	**5.2**	4.4	4.5
Total Operating Expenses	**340.9**	267.7	244.4
Operating Income	**26.1**	20.5	18.5
Other Non-Operating Expenses	**0.3**	0.3	0.2
Income Before Interest Expense	**25.8**	20.2	18.3
Interest Expense, net	**15.8**	10.5	9.6
Net Income	**10.0**	9.7	8.7
Less Dividends on Preferred Stock	**0.1**	0.1	0.1
Earnings Applicable to Common Shareholders	**$ 9.9**	$ 9.6	$ 8.6
Average Common Shares Outstanding (000's)—Basic	**9,647**	5,830	5,659
Average Common Shares Outstanding (000's)—Diluted	**9,647**	5,830	5,672
Earnings per Common Share—Basic and Diluted	**$ 1.03**	$ 1.65	$ 1.52

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS *(Millions)*

ASSETS

December 31,	2009	2008
Utility Plant:		
Electric	**$302.3**	$289.0
Gas	**325.5**	304.2
Common	**28.9**	30.5
Construction Work in Progress	**26.0**	17.7
Utility Plant	**682.7**	641.4
Less: Accumulated Depreciation	**233.0**	218.6
Net Utility Plant	**449.7**	422.8
Current Assets:		
Cash	**7.7**	11.5
Accounts Receivable—(Net of Allowance for Doubtful Accounts of $2.5 and $3.0)	**33.5**	39.7
Accrued Revenue	**44.0**	56.9
Gas Inventory	**14.3**	31.6
Material and Supplies	**2.6**	2.7
Prepayments and Other	**4.7**	5.9
Total Current Assets	**106.8**	148.3
Noncurrent Assets:		
Regulatory Assets	**144.5**	146.2
Other Noncurrent Assets	**24.2**	15.9
Total Noncurrent Assets	**168.7**	162.1
TOTAL	**$725.2**	$733.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (cont.) (Millions)

CAPITALIZATION AND LIABILITIES

December 31,	2009	2008
Capitalization:		
Common Stock Equity	**$193.1**	$139.5
Preferred Stock	**2.0**	2.0
Long-Term Debt, Less Current Portion	**248.9**	249.3
Total Capitalization	**444.0**	390.8
Current Liabilities:		
Long-Term Debt, Current Portion	**0.4**	0.4
Accounts Payable	**25.1**	28.5
Short-Term Debt	**64.5**	74.1
Energy Supply Contract Obligations	**23.1**	49.8
Other Current Liabilities	**16.6**	33.8
Total Current Liabilities	**129.7**	186.6
Deferred Income Taxes	**39.8**	31.1
Noncurrent Liabilities:		
Energy Supply Contract Obligations	**21.7**	34.6
Retirement Benefit Obligations	**65.5**	67.4
Environmental Obligations	**14.3**	12.3
Other Noncurrent Liabilities	**10.2**	10.4
Total Noncurrent Liabilities	**111.7**	124.7
TOTAL	**$725.2**	$733.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS (*Millions*)

Year Ended December 31,	2009	2008	2007
Operating Activities:			
Net Income	**$ 10.0**	$ 9.7	$ 8.7
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**27.4**	19.1	17.8
Deferred Taxes Provision	**7.1**	7.4	(0.9)
Changes in Current Assets and Liabilities:			
Accounts Receivable	**6.2**	(6.4)	(2.4)
Accrued Revenue	**12.9**	(10.3)	1.1
Gas Inventory	**17.3**	—	—
Accounts Payable	**(3.4)**	11.4	(2.2)
All Other Current Assets and Liabilities	**(3.6)**	4.6	(1.1)
Deferred Regulatory and Other Charges	**(24.6)**	2.6	3.5
Other, net	**1.6**	9.2	2.3
Cash Provided by Operating Activities	**50.9**	47.3	26.8
Investing Activities:			
Property, Plant and Equipment Additions	**(58.7)**	(28.3)	(32.5)
Acquisitions, net (See Note 2)	**(6.9)**	(209.9)	—
Cash (Used In) Investing Activities	**(65.6)**	(238.2)	(32.5)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**(9.6)**	55.3	(7.2)
Proceeds from Issuance of Long-Term Debt	**—**	90.0	20.0
Repayment of Long-Term Debt	**(0.4)**	(0.4)	(0.3)
Net Increase (Decrease) in Gas Inventory Financing	**(21.8)**	24.0	—
Dividends Paid	**(13.2)**	(8.1)	(7.9)
Proceeds from Issuance of Common Stock	**56.4**	37.4	1.5
Other, net	**(0.5)**	(0.4)	(0.4)
Cash Provided by Financing Activities	**10.9**	197.8	5.7
Net Increase (Decrease) in Cash	**(3.8)**	6.9	—
Cash at Beginning of Year	**11.5**	4.6	4.6
Cash at End of Year	**$ 7.7**	$ 11.5	$ 4.6
Supplemental Information:			
Interest Paid	**$ 19.3**	$ 12.5	$ 12.2
Income Taxes Paid (Refunded)	**$ (3.8)**	$ (0.5)	$ 5.3

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2007	$ 63.5	$ 34.3	**$ 97.8**
Net Income for 2007		8.7	**8.7**
Dividends		(7.9)	**(7.9)**
Shares Issued Under Stock Plans	0.8		**0.8**
Issuance of 38,303 Common Shares	1.0		**1.0**
Balance at December 31, 2007	65.3	35.1	**100.4**
Net Income for 2008		9.7	**9.7**
Dividends		(8.0)	**(8.0)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 32,754 Common Shares	0.8		**0.8**
Issuance of 2,000,000 Common Shares (See Note 3)	36.2		**36.2**
Balance at December 31, 2008	102.7	36.8	**139.5**
Net Income for 2009		10.0	**10.0**
Dividends		(13.2)	**(13.2)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 43,615 Common Shares	0.9		**0.9**
Issuance of 2,970,000 Common Shares (See Note 3)	55.5		**55.5**
Balance at December 31, 2009	**$159.5**	**$ 33.6**	**$193.1**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the Acquisitions). Bay State is a wholly owned subsidiary of NiSource.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the "distribution utilities").

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—The Company's consolidated financial statements include the accounts of Unitil and all of its wholly owned subsidiaries and all intercompany transactions are eliminated in consolidation. The operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from December 1, 2008 through December 31, 2009.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)	December 31, 2009	2008
Energy Supply Contract Obligations	**$ 34.7**	$ 52.7
Deferred Restructuring Costs	**28.3**	27.8
Generation-related Assets	**—**	0.8
Subtotal—Restructuring Related Items	**63.0**	81.3
Retirement Benefit Obligations	**43.7**	45.5
Income Taxes	**14.5**	16.0
Environmental Obligations	**22.7**	21.6
Deferred Storm Charges	**14.6**	—
Other	**7.9**	10.1
Total Regulatory Assets	**$166.4**	$174.5
Less: Current Portion of Regulatory Assets (1)	**21.9**	28.3
Regulatory Assets—noncurrent	**$144.5**	$146.2

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. Under the Independent System Operator—New England (ISO-NE) Financial Assurance Policy (Policy), Unitil's affiliates Unitil Energy, Fitchburg and Unitil Power are required to provide assurance of their ability to satisfy their obligations to ISO-NE. Under this Policy, Unitil's affiliates provide cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2009 and 2008, the Unitil affiliates had deposited $4.5 million and $3.7 million, respectively to satisfy their ISO-NE obligations. In addition, Northern Utilities has cash margin deposits to satisfy requirements for its natural gas hedging program. On December 31, 2009 and 2008, there was $2.9 million and $7.0 million, respectively, deposited for this purpose.

Goodwill and Intangible Assets—As a result of the acquisitions of Northern Utilities and Granite State, the Company recognized a bargain purchase adjustment as a reduction to Utility Plant, to be amortized over a ten year period, beginning with the date of the Acquisitions, as authorized by regulators. (See Note 2).

Off-Balance Sheet Arrangements—As of December 31, 2009, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases (See Note 4).

Investments and Trading Activities—The Company invests in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for accounting purposes.

Derivatives—The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases New York Mercantile Exchange (NYMEX) futures that correspond to the associated delivery month. Any gains or losses on the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company records gains and losses as regulatory liabilities or assets, recognizes such gains or losses in Purchased Gas and these gains and losses are passed through to customers through rate reconciling mechanisms.

As of December 31, 2009, the Company had 1.9 billion cubic feet (BCF) outstanding in natural gas purchase contracts under its hedging program. The following tables provide information on the hedging instruments for 2009.

Fair Value of Derivatives Designated as Hedging Instruments as of December 31, 2009 ($ millions)

Description	Balance Sheet Location	Fair Value
NYMEX Contracts	Current and NonCurrent Liabilities	$2.3

Description	Amount of Gain (Loss) Recognized in Regulatory Asset / Liability for Derivatives as of December 31, 2009	Location of Gain (Loss) Reclassified from Regulatory Asset / Liability into Consolidated Statement of Earnings	Amount of Gain (Loss) Reclassified from Regulatory Asset / Liability into Consolidated Statement of Earnings for 2009
NYMEX Contracts (1)	$(2.9)	Purchased Gas	$(9.3)

(1) Includes approximately $0.6 million of loss on contracts designated for January 2010 that were physically sold in December 2009 and the impact on the Consolidated Balance Sheet has been deferred until January 2010 when the natural gas is used.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition—Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates. See Note 9.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2009, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below. (See Note 6).

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 3.24%, 4.58% and 5.73% in 2009, 2008 and 2007, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At December 31, 2009 and December 31, 2008, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $37.2 million and $33.9 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. Depreciation provisions for Unitil's utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2009 – 4.02%, 2008 – 3.94% and 2007 – 4.29%.

Environmental Matters—The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has or will recover substantially all of the costs of the environmental remediation work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 6, Commitments and Contingencies. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation using the fair value-based method (See Note 3).

Sales and Consumption Taxes—The Company bills its customers sales tax in Massachusetts and Maine and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

Income Taxes—Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets.

Dividends—The Company is currently paying a dividend at an annual rate of $1.38 per common share. The Company's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Other Recently Issued Pronouncements—In May 2009, the FASB issued FASB ASC 855, "Subsequent Events", (ASC 855) (originally issued as SFAS No. 165, Subsequent Events), effective for interim and annual reporting periods ending after June 15, 2009. ASC 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company adopted ASC 855 and it did not have an impact on the Company's Consolidated Financial Statements. The Company evaluated all events or transactions that occurred after December 31, 2009 up through February 9, 2010.

On April 9, 2009, the FASB issued ASC 825, "Financial Instruments", (ASC 825) (originally issued as FASB Staff Position No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments".) ASC 825 requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. ASC 825 also requires those disclosures in summarized financial information at interim reporting periods. ASC 825 is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company has adopted ASC 825 and included the required disclosures in the Notes to the Company's Consolidated Financial Statements. See Note 4 for relevant disclosures on the fair value of the Company's long-term debt and Note 9 for relevant disclosures on the fair value of the Company's defined benefit pension and other postretirement plan assets.

On December 30, 2008, the FASB issued ASC 715, "Compensation—Retirement Benefits", (ASC 715) (originally issued as FASB Staff Position No. FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets") to provide guidance on an employers' disclosures about plan assets of a defined benefit pension or other postretirement plan. The disclosures about plan assets required by ASC 715 are to be provided for fiscal years ending after December 15, 2009. The Company has adopted ASC 715 and included the required disclosures in the Notes to the Company's Consolidated Financial Statements. See Note 9.

Reclassifications—Based on the Company's analysis certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation, principally including the reclassification of $7.8 million of Accounts Payable to Energy Supply Obligations and $2.0 million of Accrued Revenue to Other Current Liabilities.

Note 2: Acquisitions

On December 1, 2008, the Company purchased (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource pursuant to the Stock Purchase Agreement (SPA) dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil. The aggregate purchase price for the Acquisitions was $209.2 million, comprised of $160 million in cash, plus an additional working capital adjustment of $49.2 million. The largest component of working capital was approximately $30.0 million of natural gas storage inventory.

The Company accounted for the Acquisitions under the purchase method of accounting for business combinations, in accordance with FASB Statement No. 141, "Business Combinations" ("SFAS No. 141") and the FASB Codification on business combinations. Accordingly, the Company recognized its estimate of the bargain purchase price (see "Plant Acquisition Adjustment" in the table below) at December 1, 2008. The process of valuing the assets, liabilities and transaction, transition and financing costs as a result of the Acquisitions was completed in 2009. As a result, the Company has recognized adjustments to its original estimate of the Plant Acquisition Adjustment (PAA) during 2009.

The adjusted PAA is ($24.8 million), a decrease of $3.5 million from the original estimate of ($28.3 million). The adjusted transaction and transition Costs is an increase of $6.9 million over the original estimate, reflecting additional costs to complete the acquisition and financing. Partially offsetting the decrease in the PAA estimate due to the additional transaction and transition Costs were subsequent payments, cash settlements between the purchaser and seller and other post-closing adjustments reflecting changes to working capital, Net Utility Plant and Regulatory Liabilities.

The revised purchase price allocations are as follows:

Purchase Price Allocation
($ Millions)

	December 1, 2008
Equity Purchase Price	$ 160.0
Plus: Working Capital Adjustment	49.2
Aggregate Purchase Price	209.2
Transaction and Transition Costs	14.5
Total Cash Purchase Price	223.7
Allocation To:	
Book Value of Net Utility Plant	(197.0)
Cash Acquired	(6.9)
Accounts Receivable and Other Current Assets	(21.2)
Accrued Revenue	(7.0)
Gas Inventory	(32.3)
Regulatory Assets	(34.3)
Accounts Payable and Other Current Liabilities	20.4
Regulatory Liabilities	29.8
Plant Acquisition Adjustment	**$ (24.8)**

In accordance with settlement agreements between the Company, the New Hampshire Public Utilities Commission (NHPUC) and the Maine Public Utilities Commission (MPUC) regarding the Acquisitions, the Company has agreed (i) not to seek recovery of transaction and transition costs in rates and (ii) for regulatory accounting purposes, to amortize, over a ten year period, the transaction and transition costs co-terminus with the Plant Acquisition Adjustment. See Note 12.

Note 3: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

As of August 21, 2008 the Company's common stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's common stock trades under the symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 10,836,759, and 7,791,617 of common shares outstanding at December 31, 2009 and December 31, 2008, respectively.

Unitil Corporation Common Stock Offering—On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2008 Offering). As part of this 2008 common stock offering, the underwriters exercised an over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the 2008 Offering including the over-allotment were approximately $41.9 million. On May 27, 2009, the Company issued and sold 2,400,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2009 Offering). As part of the 2009 Offering, the underwriters exercised an over-allotment option and purchased an additional 300,000 shares of the Company's common stock in June 2009. The Company's net increase to Common

Equity and Cash proceeds from the 2009 Offering including the over-allotment was approximately $51.2 million. The combined total net increase to Common Equity and Cash proceeds from the 2008 Offering and 2009 Offering of $93.1 million (after payment of underwriting discount, but excluding offering expenses) was used to (i) repay all amounts outstanding under the bank credit facility that the Company used to partially finance the acquisition of Northern Utilities and Granite State which closed on December 1, 2008, and related transaction costs and expenses and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt.

Dividend Reinvestment and Stock Purchase Plan—During 2009, the Company sold 43,615 shares of its common stock, at an average price of $20.82 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $0.9 million were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's common stock and cash payments in additional shares of the Company's common stock. During 2008 and 2007, the Company raised $0.8 million and $1.0 million, respectively, of additional common equity through the issuance of 32,754 and 38,309 shares, respectively, of its common stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired—During 2009, 2008 and 2007, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. The Company accounts for its stock-based compensation plans in accordance with the provisions of the FASB Codification and recognizes compensation costs at fair value at the date of grant. Details of the plans are as follows:

Restricted Stock Plan—On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company common stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided for in the Plan. Awards fully vest over a period of four years at a rate of 25% each year.

During the vesting period, dividends on restricted shares underlying the award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit.

Restricted shares issued for 2007 – 2009 in conjunction with the Plan are presented in the following table:

Issuance Date	Shares	Aggregate Market Value (millions)
2/9/07	9,020	$0.2
2/6/08	15,540	$0.4
2/17/09	32,260	$0.7

The compensation expense associated with the issuance of shares under the Plan is being accrued over the vesting period and was $0.7 million, $0.5 million and $0.4 million in 2009, 2008 and 2007, respectively. At December 31, 2009, there was approximately $1.0 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over a weighted average of approximately 2.7 years as the shares vest. There were 32,043 and 21,024 non-vested shares under the Plan as of December 31, 2009 and 2008, respectively. The weighted average grant date fair value of these shares was $22.78 and $27.38, respectively. There were 733 restricted shares forfeited under the Plan during 2009. There were no cancellations under the Plan during 2008.

Unitil Corporation Key Employee Stock Option Plan—In the third quarter of 2007, the Company issued and sold 42,437 shares of its common stock, at a final average price of $10.70 per share, in connection with the exercise of stock options under the Unitil Corporation Key Employee Stock Option Plan (KESOP) which expired in 2007. The aggregate intrinsic value of the options exercised was $0.8 million. As of December 31, 2007, there are no options remaining under the KESOP. Net proceeds of $0.5 million were used by the Company to reduce short-term borrowings.

The total compensation expense recorded by the Company with respect to this plan was $57,000 for the year ended December 31, 2007. There was no compensation expense recorded for the years ended December 31, 2008 and 2009 with respect to this plan.

Share Option Activity of the KESOP is presented in the following table:

	2007
Beginning Options Outstanding and Exercisable	**25,000**
Dividend Equivalents Earned—Prior Years	**15,388**
Dividend Equivalents Earned—Current Year	**2,049**
Options Exercised	**(42,437)**
Ending Options Outstanding and Exercisable	**—**
Weighted Average Exercise Price per Share	**$10.70**
Range of Option Exercise Price per Share	**$12.11-$18.28**
Weighted Average Remaining Contractual Life	**n/a**

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's common stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. This plan was terminated on January 16, 2003 but will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan.

In 2008, the Company issued and sold 3,300 shares of its common stock, at a final average price of $24.51 per share, in connection with the exercise of stock options under the Unitil Corporation 1998 Stock Option Plan. The aggregate intrinsic value of the options exercised was less than $0.1 million. Net proceeds of $0.1 million were used by the Company to reduce short-term borrowings. There was no compensation expense associated with this plan in 2009, 2008 and 2007. No further grants of options will be made under this plan. As of December 31, 2009 and 2008, there was no aggregate intrinsic value of the options exercisable. As of December 31, 2007, the intrinsic value of the options exercisable was $0.1 million.

	2009		2008		2007	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Beginning Options Outstanding	**97,200**	**$27.16**	107,000	$27.13	107,000	$27.13
Options Granted	**—**	**—**	—	—	—	—
Options Exercised	**—**	**—**	(3,300)	$24.51	—	—
Options Forfeited / Expired	**(33,700)**	**$23.88**	(6,500)	$27.99	—	—
Ending Options Outstanding	**63,500**	**$28.90**	97,200	$27.16	107,000	$27.13
Options Vested and Exercisable- end of year	**63,500**	**$28.90**	97,200	$27.16	107,000	$27.13

The following summarizes certain data for the options outstanding at December 31, 2009:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$25.00-$29.99	33,000	$25.88	1.1 years
$30.00-$34.99	30,500	$32.17	0.1 years
	63,500		

Preferred Stock

Two of Unitil's distribution companies, Unitil Energy and Fitchburg, have $2.0 million of preferred stock outstanding. At December 31, 2009, Unitil Energy has $0.2 million of 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and Fitchburg has two series of Redeemable, Cumulative Preferred Stock outstanding, $0.8 million of 5.125% Series and $1.0 million of 8.00% Series.

Fitchburg is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, Fitchburg may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2009, 2008 and 2007 related to the annual redemption offer were $26,000, $21,200 and $21,700, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2009 is $117,000 per year.

Earnings Per Share

The following table reconciles basic and diluted earnings per share.

(Millions except shares and per share data)	2009	2008	2007
Earnings Available to Common Shareholders	**$ 9.9**	$ 9.6	$ 8.6
Weighted Average Common Shares Outstanding—Basic (000's)	**9,647**	5,830	5,659
Plus: Diluted Effect of Incremental Shares (000's)	**—**	—	13
Weighted Average Common Shares Outstanding—Diluted (000's)	**9,647**	5,830	5,672
Earnings per Share—Basic and Diluted	**$ 1.03**	$ 1.65	$ 1.52

Weighted average options to purchase 63,500, 97,200 and 35,000 shares of common stock were outstanding during 2009, 2008 and 2007, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Additionally, 28,963, 15,985 and 2,030 weighted average non-vested restricted shares for 2009, 2008 and 2007, respectively, were not included in the above computation because the effect would have been antidilutive.

Note 4: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowings under its revolving credit facility. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery, vehicles and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Long-Term Debt Structure and Covenants—The agreements under which the long-term debt of Unitil and its utility subsidiaries, Unitil Energy, Fitchburg, Northern Utilities, and Granite State, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

The long-term debt of Unitil is issued under Unsecured Promissory Notes with negative pledge provisions. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Unitil to issue new long-term debt, the covenants of the existing long-term agreement(s) must be satisfied, including that Unitil have total funded indebtedness less than 70% of total capitalization, and earnings available for interest equal to at least two times the interest charges for funded indebtedness. Each future senior long-term debt issuance of Unitil will rank pari passu with all other senior unsecured long-term debt issuances. The Unitil agreement requires that if Unitil defaults on any other future long-term debt agreement(s), it would constitute a default under its present long-term debt agreement. Furthermore, the default provisions are triggered by the defaults of Unitil Energy and Fitchburg or certain other actions against subsidiary companies in the Unitil System.

Substantially all of the property of Unitil Energy is subject to liens of indenture under which First Mortgage Bonds (FMB) have been issued. In order to issue new FMB, the customary covenants of the existing Unitil Energy Indenture Agreement must be met, including that Unitil Energy have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Unitil Energy agreements further require that if Unitil Energy defaults on any Unitil Energy FMB, it would constitute a default for all Unitil Energy FMB. The Unitil Energy default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

All of the long-term debt of Fitchburg, Northern Utilities and Granite State are issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of long-term debt ranks pari passu with its other senior unsecured long-term debt within that subsidiary. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Fitchburg, Northern Utilities or Granite State to issue new long-term debt, the covenants of the existing long-term agreements of that subsidiary must be satisfied, including that the subsidiary have total funded indebtedness less than 65% of total capitalization. Additionally, to issue new long-term debt, Fitchburg must maintain earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Unitil Energy agreements, the Fitchburg, Northern Utilities and Granite State agreements each require that if that subsidiary defaults on any of its own long-term debt agreements, it would constitute a default under all of that subsidiary's long-term debt agreements. Each of the Fitchburg, Northern Utilities and Granite State default provisions are not triggered by the actions or defaults of Unitil or any of its other subsidiaries.

The Unitil, Unitil Energy, Fitchburg, Northern Utilities and Granite State long-term debt instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets. The Granite State notes are guaranteed by Unitil for the payment of principal, interest and other amounts payable. This guarantee will terminate if Granite State is reorganized and merges with and into Northern Utilities.

At December 31, 2009, there were no restrictions on Unitil's Retained Earnings for the payment of common dividends. Unitil Energy, Fitchburg, Northern Utilities and Granite State pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil's common shareholders.

Debt Repayment and Sinking Funds—The total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $393,946, $363,755, and $335,877 in 2009, 2008, and 2007, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2009 is: 2010 – $426,643; 2011 – $462,055; 2012 – $500,405; 2013 – $541,938; and 2014 – $2,486,919, respectively.

Long-Term Debt Issuances

On December 18, 2009, both Unitil Energy and Northern Utilities priced long-term financings scheduled to close in the first quarter of 2010:

(i) Unitil Energy priced $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds were priced at a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Unitil Energy anticipates closing this long-term financing in March 2010.

(ii) Northern Utilities priced $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes were priced at a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Northern Utilities anticipates closing this long-term financing in March 2010.

The Unitil Energy and Northern Utilities securities offered will not be, and have not been, registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On May 2, 2007, Unitil completed the sale of $20 million of Senior Long-Term Notes, through a private placement to institutional investors. The Notes have a term of 15 years maturity and a coupon rate of 6.33%. The Company used the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries.

Fair Value of Long-Term Debt—Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements. If there were an active market for the Company's debt securities, the fair value of the Company's long-term debt would be estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield for December 2009. The carrying value of the Company's long-term debt at December 31, 2009 is $249.3 million. The fair value of the Company's long-term debt at December 31, 2009 is estimated to be approximately $271.6 million. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

Details on long-term debt at December 31, 2009 and 2008 are shown below:

	December 31,	
Long-Term Debt (millions)	**2009**	**2008**
Unitil Corporation Senior Notes:		
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0
Unitil Energy First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15.0**	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0
Fitchburg Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19.0**	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0
Northern Utilities Senior Notes:		
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	30.0
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	50.0
Granite State Senior Notes:		
7.15% Senior Notes, Due December 15, 2018	**10.0**	10.0
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**4.3**	4.7
Total Long-Term Debt	**249.3**	249.7
Less: Current Portion	**0.4**	0.4
Total Long-Term Debt, Less Current Portion	**$248.9**	$249.3

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Consistent with regulatory precedent, interest income is recorded on an under-collection of costs, including carrying charges of $1.1 million in 2009 on deferred storm costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)

	2009	2008	2007
Interest Expense			
Long-term Debt	**$18.2**	$12.0	$11.1
Short-term Debt	**2.1**	1.3	1.1
Regulatory Liabilities	**0.3**	0.1	0.8
Subtotal Interest Expense	**20.6**	13.4	13.0
Interest Income			
Regulatory Assets	**(3.6)**	(2.5)	(2.9)
AFUDC [1] and Other	**(1.2)**	(0.4)	(0.5)
Subtotal Interest Income	**(4.8)**	(2.9)	(3.4)
Total Interest Expense, net	**$15.8**	$10.5	$ 9.6

(1) AFUDC—Allowance for Funds Used During Construction

Credit Arrangements

At December 31, 2009, the Company had $64.5 million in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter. As of December 31, 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 13, 2009, the Company entered into an amendment to its 364-day revolving credit facility with Bank of America, as administrative agent, and a syndicate of lenders. The Company originally entered into the facility on November 26, 2008. The amendment increases the maximum borrowings under the facility from $60 million to $80 million. It also (i) decreases the upfront fees to 15 basis points of the aggregate commitment, (ii) changes the commitment fees from 30 to 40 basis points per annum of the average difference between the aggregate commitment and the outstanding borrowings, (iii) changes the margin applicable to borrowings from 1.75% to 2.0% per annum, and (iv) extends the maturity date for borrowings to October 12, 2010. Except as expressly amended by the amendment, all other terms and conditions of the facility remain in full force and effect.

The weighted average interest rates on all short-term borrowings were 3.4%, 3.8%, and 5.6% during 2009, 2008, and 2007, respectively.

Northern enters into asset management agreements under which Northern releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $10.0 million and $31.8 million outstanding at December 31, 2009 and December 31, 2008, respectively, related to these asset management agreements.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2009, 2008 and 2007 amounted to $1.0 million, $0.6 million and $0.4 million respectively. Fitchburg leases its operations facility in Fitchburg, Massachusetts under an operating lease, with a primary term through January 31, 2013. The lease agreement allows for three additional five-year renewal periods at the option of Fitchburg.

The following is a schedule of future operating lease payment obligations and future minimum lease payments under capital leases as of December 31, 2009:

Year Ending December 31, (000's)	Operating Leases	Capital Leases
2010	$1,027	$ 656
2011	906	568
2012	820	252
2013	467	53
2014	250	3
2015 – 2019	467	—
Total Payments	$3,937	$1,532

Guarantees

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2009, there were approximately $30.5 million of guarantees outstanding and the longest term guarantee extends through December 31, 2010. Of this amount, $8.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.3 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Note 5: Energy Supply

Natural Gas Supply

With the purchase of Northern Utilities on December 1, 2008, Unitil now manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and commercial and industrial (C&I) customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, although most of Fitchburg's customers continue to purchase such supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply at regulated rates from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

In the fourth quarter of 2009, the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus carrying charges, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. Fitchburg has appealed this order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Northern Utilities' service territory.

Northern has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Electric Power Supply

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third party energy suppliers. As of December 2009, 99 or 67% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 79% of Unitil's largest Massachusetts customers, representing 35% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential and small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

Prior to May 1, 2003, Unitil Energy purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, Unitil Energy and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to Unitil Energy ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, Unitil Energy continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. In connection with the restructuring of the electric industry, Unitil Power and Fitchburg divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts.

Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Note 6: Commitments and Contingencies

Legal Proceedings

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Regulatory Matters

Overview (Unitil Energy, Fitchburg, and Northern Utilities): Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territory at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next two to four years, is $63.0 million as of December 31, 2009 including $17.7 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Unitil was able to restore power to over 80 percent of its customers by day seven, and its final customers, including those with individual service problems, were restored in Massachusetts by December 24, 2008. As a result of the December 2008 Ice Storm, the Company has spent approximately $23 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.3 million related to capital construction and $14.6 million, including carrying charges, which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

On January 7, 2009, the MDPU opened an investigation into the preparation and response of the Massachusetts electric distribution companies to the December 2008 Ice Storm. Evidentiary hearings before the MDPU concerning Fitchburg's storm response were held in May, 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service. As a result, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices to address: Unitil's strategic planning processes; its staffing decisions to the extent to which they affect Fitchburg; its management and control of Fitchburg, including resource allocation decisions made among Unitil's three subsidiary companies; and customer relations. The order also directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

On July 28, 2009, Fitchburg filed with the MDPU a petition for approval to defer and record as a regulatory asset approximately $11.5 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. On December 30, 2009, the MDPU approved the request. The order of approval stated that it made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. Fitchburg anticipates filing its next rate case during the second quarter of 2010. As of December 31, 2009, Fitchburg has deferred approximately $12.3 million of costs, including carrying charges, associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On August 26, 2009, Unitil Energy filed a petition with the NHPUC requesting an accounting order authorizing Unitil Energy to record as a regulatory asset approximately $2 million in expenses associated with network damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's next base rate case. On November 9, 2009, the NHPUC granted the requested accounting order, clarifying that such issues as the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are issues that will be deferred to Unitil Energy's next rate case. Unitil Energy anticipates filing its next rate case during the second quarter 2010. As of December 31, 2009, Unitil Energy has deferred approximately $2.3 million of costs, including carrying charges, associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On December 3, 2009, the NHPUC issued its final report regarding its 'after action' review of the December 2008 Ice Storm. The after action review was a non-docketed investigation by the NHPUC of utility emergency preparedness and response. The report stated that the NHPUC will commence an adjudicative proceeding to examine the reasonableness of the timing of Unitil's response to the December 2008 Ice Storm, the priorities of its restorations and the allocation of its resources in New Hampshire and Massachusetts. On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. This matter remains pending.

Unitil Energy: On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On January 16, 2009, the NHPUC issued its decision in this matter, concluding that such rate mechanisms should only be implemented on a company-by-company basis in the context of an examination of company-specific costs and revenues, service territory, customer mix and rate base investment. On March 23, 2009, the NHPUC denied a Motion for Rehearing of this matter.

In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources. This matter remains pending before the NHPUC.

Fitchburg—Electric Operations: On November 25, 2009, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery is proposed through a Transition Charge Surcharge of $0.00400 per kWh. Changes to the Pension/ PBOP Adjustment and Residential Assistance Adjustment Factor were proposed in other proceedings. The rates were approved effective January 1, 2010, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2008 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting the items required by House Bill 4329.

Fitchburg—Gas Operations: Fitchburg provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current distribution rates were approved by the MDPU in 2007. Fitchburg's customers may purchase natural gas supplies from third-party vendors or purchase their natural gas from Fitchburg under regulated rates and tariffs. Fitchburg collects its natural gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On March 12, 2009, the MDPU opened an investigation into Fitchburg's gas procurement practices. On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

During the summer of 2009, Fitchburg operated its gas system entirely on local production from LNG for approximately three months due to construction on the lateral from Tennessee Gas Pipeline, which is the sole source of pipeline gas to Fitchburg. During this time Fitchburg provided gas LNG supply to all firm sales customers and also to the retail marketers for delivery to firm customers who have contracted for third party supply. Fitchburg's management of this project was reviewed by the MDPU during its last Integrated

Resource Plan proceeding, before the shutdown occurred. In its order, the MDPU stated it would investigate the costs associated with the shutdown in Fitchburg's March 2010 Cost of Gas Adjustment Clause filing when its actual costs will be reconciled with its projected costs.

Fitchburg—Other: On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, including company-specific rate cases. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012.

On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, and special tariffs to allow the net metering of customer-owned renewable generation. These matters, under review in separately designated dockets, remain pending, except for net metering tariffs which were approved by the MDPU effective December 1, 2009.

Northern Utilities: On December 1, 2008 Unitil completed the purchase of Northern Utilities from Bay State and Granite State from NiSource. Unopposed settlement agreements resolving all outstanding issues and recommending approval of the acquisition were approved by the NHPUC on October 10, 2008, and by the MPUC on November 5, 2008. Pursuant to its expanded authority over holding company mergers under the GC Act, the MDPU also reviewed the transaction and issued its approval on November 18, 2008.

The New Hampshire and Maine settlement agreements included the following provisions with respect to the accounting and rates of Northern Utilities:

- approval of Northern Utilities' accounting deferral and 10-year amortization of transaction costs and transition costs resulting from the Company's acquisition of Northern Utilities and the Company's agreement not to seek recovery of these costs, or the transaction or transition costs of any other utility subsidiary, in rates.
- agreement that synergy savings resulting from the acquisition of Northern Utilities will be retained by the Company until the next base rate change and then will flow to customers;
- agreement not to request a base rate change for Northern Utilities before November 1, 2010 unless (i) Northern Utilities' projected annual revenues are more than 8% below the level of total 2007 distribution revenues or (ii) the MPUC or NHPUC, as applicable, approves a plan to subject Granite State's rates to state regulation;
- agreement to allow Northern Utilities to recover prudently incurred integration costs for capitalized expenditures to build or upgrade systems or facilities required to independently operate Northern Utilities;
- agreement not to seek recovery in Northern Utilities' rates of any acquisition premium resulting from Unitil's acquisition of Northern Utilities and that any acquisition adjustment (positive or negative) shall be accounted for below the line for ratemaking purposes over a 10-year period;

- agreement to hold Northern Utilities' customers harmless for the elimination of historical accumulated deferred income tax (ADIT) liabilities resulting from its Internal Revenue Service Section 338(h)(10) election;
- agreement to use an imputed weighted cost of debt for ratemaking purposes until Northern Utilities' existing debt instruments would have matured; and
- agreement not to change Northern Utilities' existing depreciation rates for its Maine division until approved in the next general rate case.

The settlement agreements contained the following commitments related to Granite State:

- agreement to work collaboratively with the parties to the settlements to design and to conduct a comprehensive study of the issues and costs for modification of the physical, operational, regulatory, and corporate structure necessary for state regulation of Granite State and to provide a report within one year of the closing; and
- authorization for Northern Utilities to execute a firm service contract with Granite State for 100,000 Dekatherms (Dth) of capacity at Granite State's current recourse rate of $1.6666/ Dth for the period November 1, 2008 through October 31, 2010.

On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation ("NOPVs") of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern's distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at December 31, 2009 was $2.3 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in the Portland and Westbrook service areas. Northern Utilities anticipates filing testimony and a proposal for a replacement program with the MPUC by mid-February of 2010, and that proceedings will continue on this matter during the second and third quarters of 2010.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Fitchburg is in the process of developing long-range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2009 and 2008 in Environmental Obligations are accrued liabilities totaling $12.0 million and $11.1 million, respectively, related to estimated future clean up costs for permanent remediation of the Sawyer Passway site. A corresponding Regulatory Asset was recorded to reflect that the recovery of this environmental remediation cost is probable through the regulatory process. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

Northern Utilities Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800s through the mid 1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Included in the Company's Consolidated Balance Sheet at December 31, 2009 and 2008 are current and non-current accrued liabilities totaling $2.5 million and $1.6 million, respectively, associated with Northern Utilities environmental remediation obligations for these former MGP sites. A corresponding Regulatory Asset was recorded to reflect that the recovery of these environmental remediation cost is probable through the regulatory process.

The Company's ultimate liability for future environmental remediation costs, including MGP site costs, may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

The following table shows the balances and activity in the Company's liability for Environmental Obligations for 2009. The liability for Environmental Obligations was initially recognized on the Company's Consolidated Balance Sheet at December 31, 2006.

ENVIRONMENTAL OBLIGATIONS

	December 31,	
(Millions)	**2009**	**2008**
Total Environmental Obligations—Balance at Beginning of Period	**$12.7**	$12.0
Changes in Estimates	**1.8**	—
Liabilities Assumed	**—**	1.6
Payments / Reductions	**—**	0.9
Total Environmental Obligations—Balance at End of Period	**14.5**	12.7
Less: Current Portion [1]	**0.2**	0.4
Environmental Obligations—noncurrent—Balance at End of Period	**$14.3**	$12.3

(1) Reflects amounts included in Other Current Liabilities on the Company's Consolidated Balance Sheets.

Note 7: Bad Debts

Unitil's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. In 2009, 2008 and 2007, the Company recorded provisions for the energy commodity portion of bad debts of $1.9 million, $2.1 million and $1.5 million, respectively. These provisions were recognized in Purchased Electricity and Purchased Gas expense as the associated electric and gas utility revenues were billed. Purchased Electricity and Purchased Gas costs are recovered from customers through periodic rate reconciling mechanisms.

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2007 – 2009 ($ millions):

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	(a) Other	Provision	Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2009						
Electric	**$1.1**	**$ —**	**$2.3**	**$0.2**	**$1.9**	**$1.7**
Gas	**1.8**	**0.5**	**1.4**	**0.3**	**3.3**	**0.7**
Other	**0.1**	**—**	**—**	**—**	**—**	**0.1**
	$3.0	**$0.5**	**$3.7**	**$0.5**	**$5.2**	**$2.5**
Year Ended December 31, 2008						
Electric	$1.0	$ —	$2.2	$0.2	$2.3	$1.1
Gas	0.2	1.4	1.4	0.2	1.4	1.8
Other	0.1	—	—	—	—	0.1
	$1.3	$1.4	$3.6	$0.4	$3.7	$3.0
Year Ended December 31, 2007						
Electric	$1.2	$ —	$1.4	$0.2	$1.8	$1.0
Gas	0.4	—	1.0	0.1	1.3	0.2
Other	0.1	—	—	—	—	0.1
	$1.7	$ —	$2.4	$0.3	$3.1	$1.3

(a) Includes Allowance for Doubtful Accounts of Northern Utilities and Granite State, which were acquired on December 1, 2008.

Note 8: Income Taxes

Federal Income Taxes were provided for the following items for the years ended December 31, 2009, 2008 and 2007, respectively:

	2009	2008	2007
Current Federal Tax Provision (Benefit) (000's):			
Operating Income	**$(3,226)**	$(2,914)	$4,522
Total Current Federal Tax Provision (Benefit)	**(3,226)**	(2,914)	4,522
Deferred Federal Tax Provision (Benefit) (000's)			
Accelerated Tax Depreciation	**8,716**	5,159	(444)
Regulatory Assets and Liabilities	**(1,308)**	1,534	(400)
Other, net	**(120)**	121	60
Total Deferred Federal Tax Provision (Benefit)	**7,288**	6,814	(784)
Total Federal Tax Provision	**$ 4,062**	$ 3,900	$3,738

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2009, 2008 and 2007 are shown in the table below. In addition to the provisions for federal and state income taxes, the Company recorded provisions of $202,000, $165,000 and $203,000 in 2009, 2008 and 2007, respectively for New Hampshire Business Enterprise taxes, which are included in Local Property and Other Taxes on the consolidated statements of earnings.

Federal and State Tax Provision (Benefit) (000's)	2009	2008	2007
Federal			
Current	**$(3,226)**	$(2,914)	$4,522
Deferred	**7,288**	6,814	(784)
Total Federal Tax Provision	**4,062**	3,900	3,738
State			
Current	**1,376**	(42)	896
Deferred	**(218)**	592	(138)
Total State Tax Provision	**1,158**	550	758
Total Provision for Federal and State Income Taxes	**$ 5,220**	$ 4,450	$4,496

The differences between the Company's provisions for Income Taxes, including the provision for Business Enterprise taxes, and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2009	2008	2007
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**6**	5	5
Utility Plant Differences	**(3)**	(6)	(4)
Other, Net	**(1)**	(1)	—
Effective Income Tax Rate	**36%**	32%	35%

Temporary differences, including the effect of deferred tax accounting on the assets and liabilities of Northern Utilities and Granite State acquired on December 1, 2008 (see Note 2 above), which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	2009	2008
Depreciation and Utility Plant	**$ 30,318**	$ 22,611
Regulatory Assets / Liabilities & Mechanisms	**29,094**	30,071
Retirement Benefit Obligations	**(22,537)**	(23,029)
Other, net	**2,896**	1,431
Total Deferred Income Tax Liabilities	**$ 39,771**	$ 31,084

The Company evaluated its tax positions at December 31, 2009 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by the FASB Codification is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2006; December 31, 2007; and December 31, 2008. Income tax filings for the year ended December 31, 2008 have been filed with the Internal Revenue Service (IRS). In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized net operating loss (NOL) carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of $5.0 million and $6.7 million, respectively. These NOL carrybacks resulted in a refund to the Company of $4.0 million which was received in November 2009. According to Internal Revenue Code rules, NOL refunds in excess of $2.0 million fall under the jurisdiction of the Joint

Committee of Congress (Joint Committee) and are subject to review by the IRS and attorneys of the Joint Committee. As a result, on December 30, 2009, the Company received notice that its Federal Income Tax return filings for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 are under examination by the IRS. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Note 9: Retirement Benefit Plans

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan)—The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service. In September 2009, the Company amended the Pension Plan as follows:
  - The Pension Plan will be closed to non-union employees who are hired on or after January 1, 2010.
  - All non-union employees hired before January 1, 2010 will have a choice of either:
    - Remaining in the Pension Plan with the current set of benefits.

    or

    - Electing to move to Unitil Corporation's enhanced Tax Deferred Savings and Investment Plan. Non-union employees who elect this option will receive a frozen benefit from the existing Pension Plan for all of the benefits that they have accrued to December 31, 2008. This frozen benefit will not grow with future salary increases or future service. Non-union employees who elect this option will receive an enhanced employer matching contribution as well as a Company contribution in the Unitil Corporation Tax Deferred Savings and Investment Plan.
    - Union employees were not affected by this amendment.
- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan)—The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan. In 2009, the Company made the following changes to the PBOP Plan.

Changes to Utility Workers Union of America Local 341 Benefits

A new Collective Bargaining Agreement ("Agreement") was entered into between Northern Utilities, Inc., Granite State Gas Transmission, Inc. and Utility Workers Union of America Local 341 ("UWUA") for the period April 1, 2009 through March 31, 2012. Included in the Agreement were changes to retiree medical benefits under the Plan. These changes are as follows:

- Retirees under sixty-five (65) years and their dependents will be covered by the medical benefits provided by the PBOP Plan. Early retirees will be responsible for contributing 20% of the premium for medical insurance for themselves and their dependents until age sixty-five (65).
- Retirees over sixty-five (65) years will be covered by a Supplement to Medicare Plan and will be responsible for a 20% premium cost sharing.
- For all employees hired on or after April 1, 2009, no post-65 retiree medical coverage will be provided.
- The Company is to determine post-65 drug coverage to be offered to all future retirees eligible for retiree medical.

These above-referenced retiree medical provisions were effective January 1, 2010.

Changes to Non-Union Employee Benefits

In September 2009, the Company announced the following PBOP Plan changes, effective January 1, 2010, for non-union employees:

- Employees who retire on or after January 1, 2010 will pay 20% of the cost of their retiree medical benefits.
- Employees who retire on or after January 1, 2010 will not receive any cash payments towards their Medicare premiums.
- Employees who are hired on or after January 1, 2010 will only be provided with company subsidized medical insurance until they reach age 65 and will not receive a Medicare supplement plan after age 65.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP)—The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

Effective with the acquisitions of Northern Utilities and Granite State, the Company assumed the assets and obligations of the Northern Utilities and Granite State pension plans with respect to active union employees. All other active employees of Northern Utilities and Granite State effectively became members of the Company's Pension Plan as of the acquisitions closing date.

Certain employees of Northern Utilities qualified for participation in the Company's PBOP Plan effective with the acquisition closing date.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan costs for years ended December 31:	2009	2008	2007
Discount Rate [1]	**6.25%**	6.00%	5.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	8.50%	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017	2016
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 735**	$ 675	$ 690
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$ (576)**	$ (531)	$ (539)

(1) As a result of the changes to the PBOP Plan in September 2009 discussed above, the Company was required to update the discount rate used in determining the PBOP Plan costs for the remainder of 2009. Based on the market rates for long-term bonds at that time, the Company assumed a discount rate of 5.50% for the PBOP Plan from September through December of 2009.

Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.75%**	6.25%	6.00%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.50%**	8.00%	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2017	2017
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 5,887**	$ 6,084	$ 6,282
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$(4,704)**	$(4,890)	$(5,030)

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2009, 2008 and 2007, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000, $200,000 and $200,000, respectively, in the Net Periodic Benefit Cost (NPBC). The Rate of Compensation Increase assumption used for 2009, 2008 and 2007 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan			PBOP Plan			SERP		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Service Cost	**$ 2,282**	$ 1,979	$ 1,968	**$ 1,417**	$ 1,447	$ 1,431	**$217**	$150	$163
Interest Cost	**4,294**	3,800	3,336	**2,269**	2,212	2,057	**182**	126	118
Expected Return on Plan Assets	**(4,432)**	(4,390)	(4,195)	**(440)**	(325)	(245)	**—**	—	—
Prior Service Cost Amortization	**264**	119	106	**1,634**	1,390	1,360	**(2)**	(1)	(2)
Transition Obligation Amortization	**—**	—	—	**21**	21	21	**—**	—	—
Curtailment Loss	**32**	—	—	**—**	—	—	**—**	—	—
Actuarial Loss Amortization	**1,598**	1,274	1,345	**—**	—	70	**70**	24	44
Sub-total	4,038	2,782	2,560	4,901	4,745	4,694	467	299	323
Amounts Capitalized and Deferred	**(1,409)**	(893)	(873)	**(1,642)**	(1,872)	(2,033)	**—**	—	—
NPBC Recognized	**$ 2,629**	$ 1,889	$ 1,687	**$ 3,259**	$ 2,873	$ 2,661	**$467**	$299	$323

The estimated amortizations related to Actuarial Loss and Prior Service Cost included in the Company's Retirement plan costs over the next fiscal year is $2.7 million, $1.6 million and $0.1 million for the Pension, PBOP and SERP plans, respectively.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2009, 2008 and 2007 before capitalization and deferral was $4.0 million, $2.8 million and $2.6 million, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2009, 2008 and 2007 would have been $6.3 million, $2.9 million and $2.5 million respectively.

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan		PBOP Plan		SERP	
Change in Plan Assets:	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**
Plan Assets at Beginning of Year	**$ 39,124**	$ 52,162	**$ 4,361**	$ 4,144	**$ —**	$ —
Actual Return on Plan Assets	**8,017**	(15,542)	**874**	(784)	**—**	—
Employer Contributions	**4,227**	2,800	**2,800**	2,700	**53**	59
Participant Contributions	**—**	—	**2**	—	**—**	—
Acquired Plan Assets	**(544)**	2,500	**—**	—	**—**	—
Benefits Paid	**(3,742)**	(2,796)	**(1,731)**	(1,699)	**(53)**	(59)
Plan Assets at End of Year	**$ 47,082**	$ 39,124	**$ 6,306**	$ 4,361	**$ —**	$ —
Change in PBO:						
PBO at Beginning of Year	**$ 70,386**	$ 64,429	**$ 37,655**	$ 37,983	**$ 2,930**	$ 2,144
Service Cost	**2,282**	1,979	**1,417**	1,447	**217**	150
Interest Cost	**4,294**	3,800	**2,269**	2,212	**182**	126
Participant Contributions	**—**	—	**2**	—	**—**	—
Plan Amendments	**—**	—	**(2,382)**	—	**—**	—
Estimated Acquired Obligations	**—**	4,442	**—**	2,610	**—**	—
Curtailment Gain	**(599)**	—	**—**	—	**—**	—
Benefits Paid	**(3,742)**	(2,796)	**(1,731)**	(1,699)	**(53)**	(59)
Actuarial (Gain) or Loss	**6,667**	(1,468)	**(1,536)**	(4,898)	**703**	569
PBO at End of Year	**$ 79,288**	$ 70,386	**$ 35,694**	$ 37,655	**$ 3,979**	$ 2,930
Funded Status: Assets vs PBO	**$(32,206)**	$(31,262)	**$(29,388)**	$(33,294)	**$(3,979)**	$(2,930)

The Company has recorded on its balance sheets as a liability the underfunded status of their retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets of $43.7 million and $45.5 million at December 31, 2009 and 2008, respectively, to recognize the future collection of these plan obligations in electric and gas rates.

The Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $69.0 million and $61.1 million as of December 31, 2009 and 2008, respectively. The ABO for the SERP was $0.5 million and $0.5 million as of December 31, 2009 and 2008, respectively. For the PBOP Plan, the ABO and PBO are the same.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in

the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 – 2010 plan years. This did not affect the Company's Pension Plan in 2009 as its Pension Plan was 94% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2009 and met the exemption from the shortfall amortization. The Company expects to contribute approximately $4.0 million to fund its Pension Plan in 2010.

The following table represents employer contributions and benefit payments ($000's). There were no participant contributions.

	Pension Plan			PBOP Plan			SERP		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Employer Contributions	**$4,227**	$2,800	$2,800	**$2,800**	$2,700	$2,500	**$53**	$59	$72
Benefit Payments	**$3,742**	$2,796	$2,645	**$1,731**	$1,699	$1,497	**$53**	$59	$72

The following table represents estimated future benefit payments ($000's).

	Estimated Future Benefit Payments		
	Pension	PBOP	SERP
2010	$ 3,585	$ 1,309	$ 52
2011	3,685	1,431	51
2012	3,906	1,526	50
2013	4,138	1,610	363
2014	4,376	1,725	362
2015 - 2019	$25,369	$10,047	$1,782

The Expected Long-Term Rate of Return on Pension Plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on Pension Plan assets is based on target investment allocation of 57% in common stock equities and 43% in fixed income securities. The Company's Expected Long-Term Rate of Return on PBOP Plan assets is based on target investment allocation of 55% in common stock equities and 45% in fixed income securities. The actual investment allocations are shown in the tables below.

Pension Plan	Target Allocation 2010	Actual Allocation at December 31, 2009	2008	2007
Equity Securities	57%	**59%**	54%	57%
Debt Securities	43%	**40%**	35%	43%
Other	0%	**1%**	11%	0%
Total		**100%**	100%	100%

PBOP Plan	Target Allocation 2010	Actual Allocation at December 31, 2009	2008	2007
Equity Securities	55%	**56%**	56%	0%
Debt Securities	45%	**44%**	44%	0%
Other (1)	0%	**0%**	0%	100%
Total		**100%**	100%	100%

(1) Represents investments in Money Market Funds.

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2009. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 5 – 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The FASB Codification defines fair value, and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under the FASB Codfiication are described below:

Level 1 – Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3 – Prices or valuations that require inputs that are both significant to the fair value measurement and unobservable.

To the extent that valuation is based on models or inputs that are less observable or unobservable in the market, the determination of fair value requires more judgment. Accordingly, the degree of judgment exercised by the Company in determining fair value is greatest for instruments categorized in Level 3. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Fair value is a market-based measure considered from the perspective of a market participant rather than an entity-specific measure. Therefore, even when market assumptions are not readily available, the Company's own assumptions are set to reflect those that market participants would use in pricing the asset or liability at the measurement date. The Company uses prices and inputs that are current as of the measurement date, including during periods of market dislocation. In periods of market dislocation, the observability of prices and inputs may be reduced for many instruments. This condition could cause an instrument to be reclassified from Level 1 to Level 2 or from Level 2 to Level 3.

Valuation Techniques

There have been no changes in the valuation techniques used during the current period.

Assets measured at fair value on a recurring basis for the Pension Plan as of December 31, 2009 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Pension Plan Assets:				
Trading Securities	**$46,667**	$46,667	$—	$—
Escrow	**415**	415		
Total Assets	**$47,082**	$47,082	$—	$—

Assets measured at fair value on a recurring basis for the PBOP Plan as of December 31, 2009 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
PBOP Plan Assets:				
Trading Securities	**$6,306**	$6,306	$—	$—
Total Assets	**$6,306**	$6,306	$—	$—

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company common stock fund.

In September 2009, the Company amended the Plan as follows:

For current non-union employees who elect to stay with the Company's existing Pension Plan, there will be no changes in the 401(k) Plan. For those employees, the Company will continue to match contributions, with a maximum matching contribution of 3% of current compensation and those participants will be 100% vested in these company matching contributions once they have completed three years of service.

For non-union employees who are hired on or after January 1, 2010, and for non-union employees who elect to move from the Company's existing Pension Plan and accept a frozen pension benefit, the Company will provide the following enhancements to the 401(k) Plan:

- The Company will contribute 4% of base pay each year, regardless of whether or not the non-union employee elects to contribute to the 401(k) Plan.
- The Company will increase the matching contributions from 3% of base pay to 6% of base pay. This will be a 100% match of the first 6% of the non-union employee's contributions.
- All Company contributions will be 100% vested at all times.
- New non-union employees will be automatically enrolled in the 401(k) Plan following the completion of 1,000 hours of service, with the automatic employee contribution rate of 3%. This contribution rate will automatically increase by 1% on January 1st of each year until the non-union employee's contribution is 10% of pay. Non-union employees may elect to opt-out of the automatic enrollment and/or automatic increase features of the enhanced 401(k) Plan.

The Company's share of contributions to the 401(k) Plan was $671,000, $542,000 and $533,000 for the years ended December 31, 2009, 2008, and 2007, respectively.

Note 10: Segment Information

Unitil reports four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine.

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transmission services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty, Unitil Service and the holding company are included in the “Other” column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company’s corporate headquarters. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries’ use. Unitil Resources and Usource are included in the Non-Regulated column below.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes and preferred stock dividends. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on cost allocation factors included in rate applications approved by the NHPUC, MDPU, and MPUC. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2009, 2008 and 2007 (Millions):

Year Ended December 31, 2009	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$209.9**	**$152.8**	**$ —**	**$ 4.3**	**$367.0**
Interest Income	**3.6**	**0.5**	**0.7**	**—**	**4.8**
Interest Expense	**9.1**	**9.7**	**1.8**	**—**	**20.6**
Depreciation & Amortization Expense	**14.0**	**12.8**	**0.6**	**—**	**27.4**
Income Tax Expense (Benefit)	**2.4**	**1.9**	**(0.1)**	**1.0**	**5.2**
Segment Profit (Loss)	**4.9**	**3.3**	**0.1**	**1.6**	**9.9**
Segment Assets	**347.9**	**367.4**	**7.3**	**2.6**	**725.2**
Capital Expenditures	**27.7**	**30.0**	**1.0**	**—**	**58.7**
Year Ended December 31, 2008					
Revenues	$227.5	$ 56.9	$ —	$ 3.8	$288.2
Interest Income	2.2	0.1	0.3	—	2.6
Interest Expense	8.7	2.3	2.1	—	13.1
Depreciation & Amortization Expense	13.1	5.2	0.8	—	19.1
Income Tax Expense (Benefit)	1.9	2.6	(0.3)	0.2	4.4
Segment Profit (Loss)	5.2	4.3	(0.2)	0.3	9.6
Segment Assets	359.2	363.9	9.1	1.0	733.2
Capital Expenditures	19.7	7.6	1.0	—	28.3
Year Ended December 31, 2007					
Revenues	$225.0	$ 34.2	$ —	$ 3.7	$262.9
Interest Income	2.8	0.1	0.5	—	3.4
Interest Expense	9.6	2.1	1.3	—	13.0
Depreciation & Amortization Expense	12.6	3.8	1.3	0.1	17.8
Income Tax Expense (Benefit)	3.8	0.4	0.1	0.2	4.5
Segment Profit (Loss)	7.3	1.0	—	0.3	8.6
Segment Assets	351.9	110.3	11.7	0.7	474.6
Capital Expenditures	26.2	6.1	0.2	—	32.5

Note 11: Quarterly Financial Information (unaudited; Millions, except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding and the impact of additional commons share issuances. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2009	2008	2009	2008	2009	2008	2009	2008
Total Operating Revenues	**$135.6**	$ 71.9	**$ 71.5**	$ 59.4	**$ 70.4**	$ 69.1	**$ 89.5**	$ 87.8
Operating Income	**$ 13.9**	$ 6.0	**$ 4.2**	$ 4.2	**$ 3.4**	$ 3.9	**$ 4.6**	$ 6.4
Net Income (Loss) Applicable to Common	**$ 9.1**	$ 3.3	**$ 0.2**	$ 1.6	**$ (0.6)**	$ 1.5	**$ 1.2**	$ 3.2
	Per Share Data:							
Earnings Per Common Share	**$ 1.14**	$ 0.57	**$ 0.03**	$ 0.28	**$ (0.06)**	$ 0.27	**$ 0.11**	$ 0.53
Dividends Paid Per Common Share	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345

Note 12: Unaudited Pro Forma Financial Data Related To Acquisitions

On December 1, 2008, the Company acquired Northern Utilities and Granite State, as discussed in Note 2. Had the results of operations for Northern Utilities and Granite State been combined with the Company as of the beginning of 2007, the Company's pro forma results for 2008 and 2007 would have been as follows:

(Millions, except per share amounts) (Unaudited)	Year ended December 31, 2008	Year ended December 31, 2007
Revenues	**$395.5**	$396.2
Earnings Applicable to Common Shareholders	**$ 8.3**	$ 11.5
Earnings per Share		
Basic	**$ 0.77**	$ 1.08
Diluted	**$ 0.77**	$ 1.08

The Unaudited Pro Forma Financial Data includes non-recurring charges to operating expenses of $1.7 million, after tax, related to compliance violation penalties incurred by Northern Utilities in 2007 and $2.5 million, after tax, related to compliance violation penalties incurred by Northern Utilities in 2008.

The Unaudited Pro Forma Financial Data are presented for illustrative purposes only and do not indicate the financial results of the combined companies had the companies actually been combined and had the impact of possible revenue enhancements and expense efficiencies, among other factors, been considered, and is not intended to be a projection of future results.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of December 31, 2009. Based upon this evaluation, the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded as of December 31, 2008 that the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) are effective.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). In addition, management is required to report their assessment, including their evaluation criteria, on the design and operating effectiveness of the Company's internal control over financial reporting in this Form 10-K.

The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The Company's internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles. The Company's internal control over financial reporting includes policies and procedures which provide reasonable assurances that transactions are properly initiated, authorized, recorded, reported and disclosed, and provide reasonable assurances regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

During 2009, management conducted an assessment of the Company's internal control over financial reporting reflected in the financial statements, based upon criteria established in the "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Based on management's assessment, which included a comprehensive review of the design and operating effectiveness of the Company's internal control over financial reporting, management believes the Company's internal control over financial reporting is designed and operating effectively as of December 31, 2009.

The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by Caturano and Company, an independent registered public accounting firm. Their report appears in Item 8.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

On December 18, 2009, both Unitil Energy and Northern Utilities priced long-term financings scheduled to close in the first quarter of 2010:

(iii) Unitil Energy priced $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds were priced at a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Unitil Energy anticipates closing this long-term financing in March 2010.

(iv) Northern Utilities priced $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes were priced at a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Northern Utilities anticipates closing this long-term financing in March 2010.

The Unitil Energy and Northern Utilities securities offered will not be, and have not been, registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Compensation Discussion and Analysis" and "Compensation of Named Executive Officers" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the "Beneficial Ownership" and "As to the Election of Directors" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010, as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this Item is set forth in the "Transactions with Related Persons" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2009 and 2008
- Consolidated Statements of Earnings for the years ended December 31, 2009, 2008, and 2007
- Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008, and 2007
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2009, 2008, and 2007
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	Articles of Amendment to the Articles of Incorporation Filed on September 23, 2008.	Exhibit 3.3 to Form S-3/A dated November 25, 2008
3.4	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.5	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.6	Articles of Exchange of CECo, E&H, and the Company - Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.7	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (Fitchburg) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.8	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989

Exhibit Number	Description of Exhibit	Reference*
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002
4.2	Fitchburg Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.3	Fitchburg Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.4	Fitchburg Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.5	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.6	Fitchburg Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.7	Fitchburg Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
4.8	Thirteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of September 26, 2006.	**
4.9	Unitil Corporation Note Purchase Agreement, dated as of May 2, 2007, for the 6.33% Senior Notes due May 1, 2022.	**
4.10	Northern Utilities Note Purchase Agreement, dated as of December 3, 2008, for the 6.95% Senior Notes, Series A due December 3, 2018 and the 7.72% Senior Notes, Series B due December 3, 2038.	Exhibit 4.1 to Form 8-K dated December 3, 2008
4.11	Granite State Note Purchase Agreement, dated as of December 15, 2008, for the 7.15% Senior Notes due December 15, 2018	Exhibit 99.1 to Form 8-K dated December 15, 2008
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 8-K dated June 19, 2008
10.5***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.3 to Form 8-K dated June 19, 2008
10.6***	Amended and Restated Unitil Corporation Supplemental Executive Retirement Plan effective as of December 31, 2007.	Exhibit 10.4 to Form 8-K dated June 19, 2008

Exhibit Number	Description of Exhibit	Reference*
10.7***	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.8***	Amended and Restated Unitil Corporation Management Incentive Plan effective as of June 19, 2008 as further amended on December 1, 2008.	Exhibit 10.8 to Form 10-K for 2008
10.9	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.10***	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.11	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.12	Unitil Corporation Tax Deferred Savings and Investment Plan—Trust Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2004
10.13***	Amended and Restated Employment Agreement effective as of November 1, 2009 by and between Unitil Corporation and Robert G. Schoenberger.	Exhibit 10.1 to Form 8-K dated September 23, 2009
10.14	Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated November 26, 2008
10.15	Amendment Agreement dated as of January 2, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated January 2, 2009
10.16	Amendment Agreement dated as of October 13, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated October 13, 2009
10.17	Credit Agreement between Unitil Corporation and Royal Bank of Canada dated December 1, 2008	Exhibit 10.2 to Form 8-K dated November 26, 2008
10.18	Transition Services Agreement between Unitil Corporation and NiSource, Inc. dated December 1, 2008	Exhibit 10.3 to Form 8-K dated November 26, 2008
10.19	Parent Guaranty of Unitil Corporation for the Granite State 7.15% Senior Notes due December 15, 2018	Exhibit 10.1 to Form 8-K dated December 15, 2008
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith

Exhibit Number	Description of Exhibit	Reference*
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** In accordance with Item 601(b)(4)(iii)(A) of Federal Securities Regulation S-K, the instrument defining the debt of the Registrant and its subsidiary, described above, has been omitted but will be furnished to the Commission upon request.

*** These exhibits represent a management contract or compensatory plan.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 10, 2010

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board of Directors,
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 10, 2010
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 10, 2010
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	February 10, 2010
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 10, 2010
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 10, 2010
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 10, 2010
/s/ WILLIAM D. ADAMS **William D. Adams**	Director	February 10, 2010
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 10, 2010
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 10, 2010
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 10, 2010
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 10, 2010
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 10, 2010
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	February 10, 2010

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2009	2008	2007
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$10,049**	$9,735	$8,746
Less: Dividend Requirements on Preferred Stock	**134**	135	136
Net Income Applicable to Common Stock	**$ 9,915**	$9,600	$8,610
Average Number of Common Shares Outstanding—Basic	**9,647**	5,830	5,659
Dilutive Effect of Stock Options and Restricted Stock	**—**	—	13
Average Number of Common Shares Outstanding—Diluted	**9,647**	5,830	5,672
Earnings Per Share—Basic	**$ 1.03**	$ 1.65	$ 1.52
Earnings Per Share—Diluted	**$ 1.03**	$ 1.65	$ 1.52

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

(000's, except ratios)	Year Ended December 31, 2009	2008	2007	2006	2005
Earnings:					
Net Income, per Consolidated Statements of Earnings	**$10,049**	$ 9,735	$ 8,746	$ 8,033	$ 8,553
Federal and State Income Taxes included in Operations	**5,220**	4,450	4,482	4,266	4,275
Interest on Long-Term Debt	**17,961**	11,795	10,919	9,404	8,319
Amortization of Debt Discount Expense	**233**	151	136	112	104
Other Interest	**2,474**	1,156	1,949	1,675	1,046
Total	**$35,937**	$27,287	$26,232	$23,490	$22,297
Fixed Charges:					
Interest on Long-Term Debt	**$17,961**	$11,795	$10,919	$ 9,404	$ 8,319
Amortization of Debt Discount Expense	**233**	151	136	112	104
Other Interest	**2,474**	1,156	1,949	1,675	1,046
Pre-tax Preferred Stock Dividend Requirements	**208**	199	213	208	234
Total	**$20,876**	$13,301	$13,217	$11,399	$ 9,703
Ratio of Earnings to Fixed Charges	**1.72**	2.05	1.98	2.06	2.30

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has eight wholly-owned subsidiaries, seven of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Northern Utilities, Inc., Granite State Gas Transmission, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The eighth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements of Unitil Corporation and subsidiaries on Form S-3 (File No. 333-158537 effective April 29, 2009), Form S-3 (File No. 333-152823 effective December 5, 2008), Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000) of our report dated February 10, 2010, relating to the consolidated financial statements of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and 2008 and the three years ending December 31, 2009 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, appearing in the Annual Report of the Company on Form 10-K for the year ended December 31, 2009.

Caturano and Company P.C.

Boston, Massachusetts
February 10, 2010

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2010

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2010

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2010

/s/ Laurence M. Brock

Laurence M. Brock

Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 10, 2010
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 10, 2010
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 10, 2010

INFORMATION

2010 Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at the office of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 15, 2010, at 10:30 a.m.

Investor Information

The Company's Transfer Agent, Computershare Trust Company, N.A. ("Computershare"), is responsible for all shareholder records, including stock transfer and the distribution of dividends, tax documents and annual meeting materials to registered holders. Shareholder requests regarding these and other matters can be addressed by corresponding directly with Computershare at:

Mail: PO Box 43078
Providence, RI 02940-3078

Telephone: 800-736-3001

Web site: www.computershare.com

For information about the Company and your investment, you may also call the Company directly, toll-free, at: 800-999-6501 and ask for the Shareholder Representative; or visit the Investor Relations page at www.unitil.com; or contact us at InvestorRelations@unitil.com.

PROGRAMS and PLANS

Dividend Reinvestment Plan

A Dividend Reinvestment and Stock Purchase Plan is available to registered holders of the Company's Common Stock. This Plan provides shareholders with an economical means to increase their investment in the Company each quarter by reinvesting their dividends without broker fees. For additional information or enrollment, please contact the Company or Computershare.

Dividend Direct Deposit

Dividend Direct Deposit Service is available without charge to shareholders of record of the Company's Common Stock. For further information or enrollment in this service, please contact the Company or Computershare.

Direct Registration

The Company's Common Stock is eligible for Direct Registration or "DRS", which is available without charge to shareholders of record. DRS is a service within the securities industry that allows shares to be held and tracked electronically, without having to retain a physical stock certificate. For additional information, please contact Computershare at:

Mail: PO Box 43084
Providence, RI 02940-3084

Telephone: 800-736-3001

Web site: www.computershare.com

Unitil Corporation • 6 Liberty Lane West • Hampton, NH 03842-1720

Mixed Sources
Product group from well-managed
forests and other controlled sources
www.fsc.org Cert no. SCS-COC-000648
© 1996 Forest Stewardship Council
FSC

The paper used in the production of this
booklet is FSC Certified and is harvested
under environmentally responsible conditions.
It is printed using vegetable-based inks.

002CS-1A151

energy for life.

a new way to describe our long history of commitment

Unitil

2010 Annual Report

Rick Ahlin
Supervisor, Gas Systems Operations
18 years of service

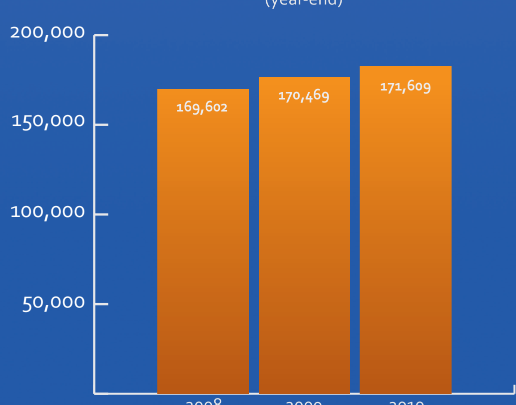
UNITIL'S DISTRIBUTION UTILITIES SERVICE AREAS

ABOUT UNITIL

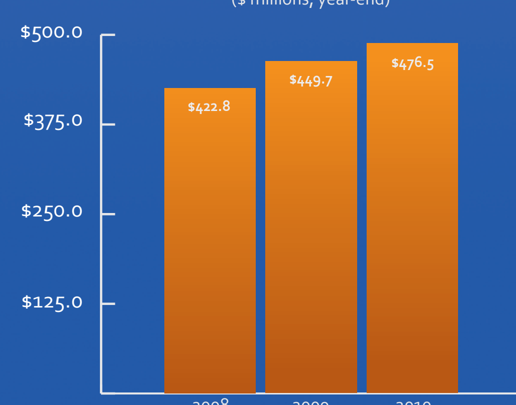
Unitil Corporation provides for the necessities of life, safely and reliably delivering natural gas and electricity throughout New England. We are committed to the communities we serve and to developing people, business practices, and technologies that lead to dependable, more efficient energy. Unitil Corporation is a public utility holding company with affiliates that include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc., and Granite State Gas Transmission, Inc. Together, Unitil Corporation's operating utilities serve approximately 100,900 electric customers and 70,800 natural gas customers. Other subsidiaries include Unitil Service Corp. and its non-regulated business segment doing business as Usource. For more information about our people, technologies, and community involvement please visit www.unitil.com.

FINANCIAL HIGHLIGHTS	2010	2009	2008
Financial Data (Millions)			
Total Operating Revenues	$358.4	$367.0	$288.2
Total Operating Income	$28.0	$26.1	$20.5
Capital Expenditures	$49.6	$58.7	$28.3
Earnings Applicable to Common	$9.5	$9.9	$9.6
Net Utility Plant	$476.5	$449.7	$422.8
Common Share Data			
Diluted Earnings per Share	$.88	$1.03	$1.65
Dividends Paid Per Common Share	$1.38	$1.38	$1.38
Book Value Per Share (Year-End)	$17.35	$17.83	$17.90
Market Price (Year-end)	$22.74	$22.98	$20.65
Average Common Shares Outstanding (000's)	10,824	9,647	5,830
Operating Data			
Electric Distribution Sales (Millions of kWh)	1,691.1	1,618.8	1,695.9
Firm Gas Distribution Sales (Millions of Therms)	172.9	178.7	47.2
Customers Served (Year-End)	171,609	170,469	169,602
Electric Customers Served (Year-End)	100,858	100,498	100,324
Gas Customers Served (Year-End)	70,751	69,971	69,278

Total Customers Served
(year-end)



Net Utility Plant
($ millions, year-end)



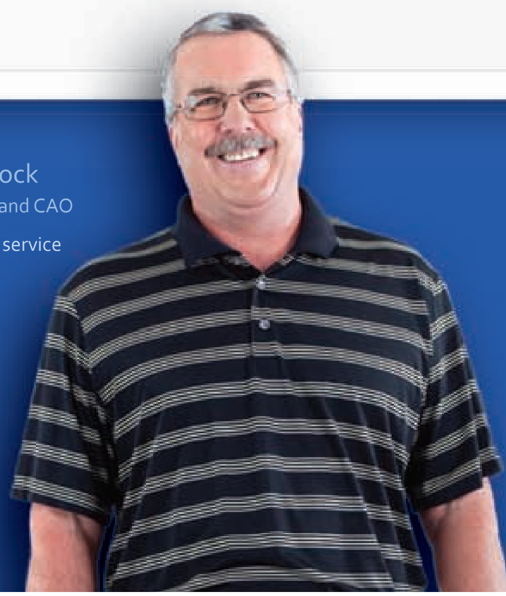
"We are in the business of providing for the necessities of life, safely and reliably delivering natural gas and electricity throughout New England. We adhere to a set of core principles that has guided, and will continue to guide, the way we do business and interact with all stakeholders in the future."

Robert G. Schoenberger
Chairman of the Board of Directors,
President and Chief Executive Officer

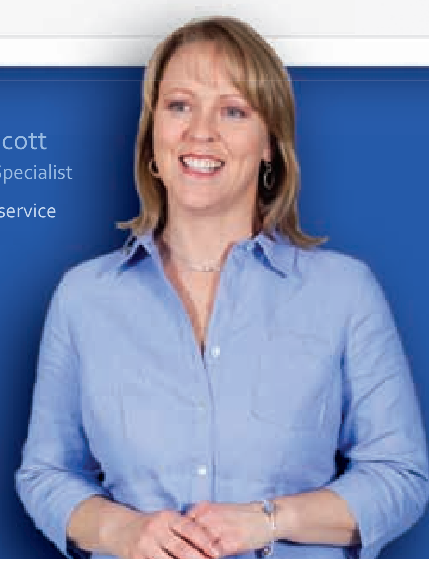
TO OUR SHAREHOLDERS

2010 was a challenging year for our company. We earned $0.88 per share compared to $1.03 per share in 2009. Our 2010 financial results reflect a warmer than normal heating season, a slow economic recovery and higher operating expenses. But the year also marked a turnaround towards improving financial performance as we initiated our regulatory agenda to reset rates in all of our regulatory jurisdictions. As we complete these rate cases, we expect to show marked improvement in earnings and overall financial strength. I will go into the details of our financial and regulatory plan later in this letter, but first I would like to discuss some examples of our accomplishments in the last year and how they help to describe who we are and how we do business.

Larry Brock
Controller and CAO
15 years of service



Becky Scott
Program Specialist
3 years of service

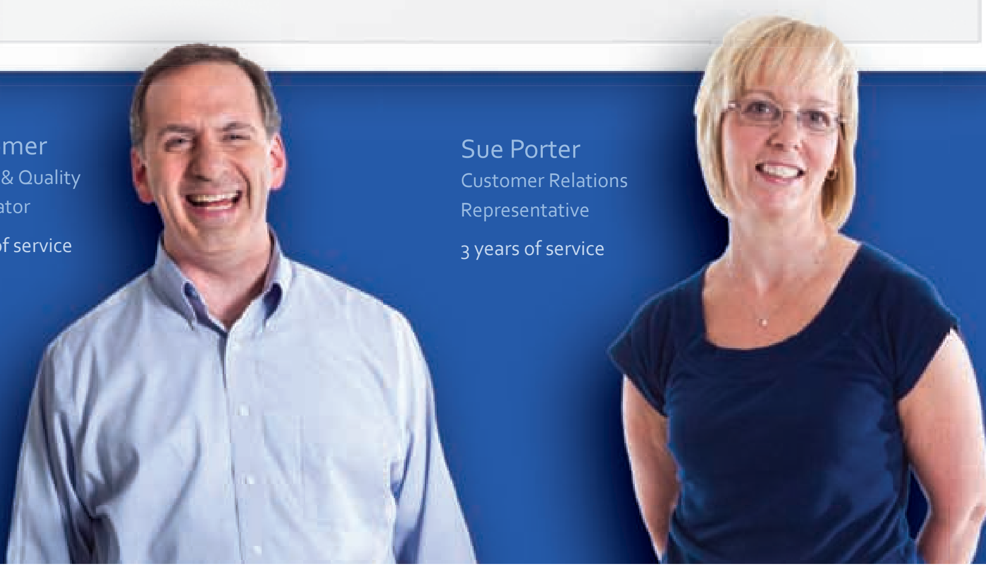


We are in the business of providing for the necessities of life, safely and reliably delivering natural gas and electricity to our customers. We adhere to a set of core principles that has guided, and will continue to guide, the way we do business and interact with our customers and other stakeholders. Over the past two years, we spent a considerable amount of time and resources modernizing our emergency preparedness procedures and operational performance. We adopted the National Incident Management System, which is used by both federal and state governments as the standard model for emergency response. We also added personnel and trained all of our employees to respond to an emergency of any size.

In February of 2010, we had an opportunity to test the effectiveness of our new emergency preparedness procedures and operations in response to a devastating wind storm. The storm, which carried hurricane-force winds, ranked as the second worst storm in New Hampshire state history in terms of power interruptions. At the peak, more than 360,000 customers in New Hampshire were without power, second only to the December 2008 ice storm when 430,000 customers were interrupted. Over 80% of our electric customers in New Hampshire (the most in history) lost power, worse than the 2008 ice storm. In the end, we restored power to all our customers within three and a half days, an outstanding achievement by all measures given the destruction and devastation caused by this late winter storm. Our quick and efficient response received praise from our customers, government officials, local fire and police departments and the media.

Safety is our top priority for our employees and the communities we serve. Our dedication to safety was honored by the Northeast Gas Association (NGA) where we were the recipient of the NGA's first ever "Excellence in Safety and Health" award for a new program where all of our first responders were trained and outfitted with state-of-the-art safety equipment. Another aspect of our safety program involves on-the-job training with local fire and police departments to improve coordination in the event of an emergency. A good working relationship with local emergency responders is vital for maintaining a safe working environment for our employees and customers.

In 2010, we continued to invest in technological improvements in our utility infrastructure to enhance our operational performance. In 2010, we launched new outage management systems to monitor our electric and gas distribution infrastructure. These systems are used to centralize critical planning processes, which facilitates safe and efficient restoration of gas and electric service to customers following an interruption.



Jim Pomer
Training & Quality Coordinator

2 years of service

Sue Porter
Customer Relations Representative

3 years of service

In a constantly changing environment, what continues to drive and fuel our company is the dedication of our employees and the capital improvements in which we invest. One area where this comes into play is our cast iron replacement program in Maine. This plan seeks to replace 113 miles of natural gas pipeline throughout Portland and Westbrook, Maine, with the support of our state regulators and other stakeholders. We are updating our distribution system to state-of-the-art plastics that will enable Unitil to safely grow and meet the demand of these communities. This program benefits our customers by improving the safety and reliability of our natural gas distribution system and providing a cost-effective opportunity to switch to natural gas. The University of Southern Maine (USM) in Portland, Maine, will be switching to natural gas during the 2011 heating season. The conversion from oil to natural gas will save USM an estimated $315,000 next year in energy costs.

We also implemented several pilot programs throughout 2010 to test innovative clean energy-saving ideas. For example, in Exeter, New Hampshire, we worked with a local entrepreneur who installed 500 solar panels at Exeter High School, which are designed to generate enough power to meet 5 to 10 percent of the school's energy needs and to save approximately $20,000 a year in energy costs.

Energy for Life is our new positioning statement launched in 2010 that speaks to the communities and neighborhoods that we serve about who we are and how we do business. We back up this statement with support for events and organizations that energize our communities and benefit our neighbors. One of our most popular employee benefits is paid time off to volunteer at a charity of the employee's choice – a benefit that provides value to our customers and motivates our employees. To help coordinate this effort, we have partnered with the United Way for their Day of Caring events where there is always a strong turnout from our employees. We are constantly looking for opportunities to contribute in other ways as well, and between corporate donations and our employee-driven local donation committees, we gave over $250,000 in 2010 across our service territories to important non-profit organizations and causes.

Looking forward, we will continue to look for ways to enhance our community service and partnerships. One of the areas we have highlighted is education. In 2011, in addition to continuing our energy education and energy efficiency programs for all our customers, we will establish scholarships in each of our service territories for graduating high school seniors to encourage careers in engineering, math and the sciences. We have also finalized a partnership with the American Red Cross that focuses on reciprocal training, joint safety-messaging during emergencies, volunteer opportunities, and other community-driven initiatives.

2010 Financial Results and Regulatory Plan

In 2010, we reported earnings of $9.5 million, or $0.88 per share, compared to earnings of $9.9 million, or $1.03 per share, in 2009. As I noted in last year's letter, we recorded a non-recurring accounting charge of $4.9 million for a gas refund in the fourth quarter of 2009 which negatively impacted earnings by ($0.30) per share in that quarter. Our 2010 full year results were adversely impacted by lower natural gas sales due to a warm winter heating season to start the year. An increase in electric sales year over year, as well as higher gas sales in the fourth quarter of 2010 are welcome signs that the regional economy is improving and with it our sales growth.

The increase in sales combined with the resetting of rates in all of our operating utilities by the end of 2011 will strengthen our financial position to the benefit of our customers and shareholders.

Our non-regulated energy brokering subsidiary, Usource, reported segment earnings of $1.5 million, or $0.14 per share, on revenues of $4.6 million in 2010. Usource also had a forward book of approximately $8 million in revenues at the end of the year. Usource serves 1,200 customers in 18 states and had a 98% retention rate last year. With natural gas prices remaining favorable compared to oil, we expect continued strong demand for Usource's services.

On a weather-normalized basis, electric unit sales in 2010 increased approximately 1.6% year-over-year, and 2.9% in the fourth quarter compared to 2009. Weather-normalized natural gas therm sales for the full year of 2010 were essentially flat with therm sales in 2009, and, importantly, increased approximately 2% in the fourth quarter. As you can see, our 2010 sales, especially in the fourth quarter, reflected solid growth for both our electric and gas operations.

To unlock the full earnings power of our distribution utilities, our regulatory strategy entails base rate case proceedings for all of our utility operating companies through the end of 2011. During this process, we expect to reset our base distribution rates that should allow our distribution utilities to recover their cost of service and earn a compensatory return.

On July 1, 2010, we obtained a temporary rate increase of $5.2 million per year at our New Hampshire electric distribution subsidiary. We are currently in settlement discussions regarding the permanent rate level and a long-term rate plan, which will include future rate "step" adjustments to track capital spending, without the need for a full rate case proceeding. A final hearing has been scheduled, and permanent rates will go into effect May 1, 2011, but will be reconciled back to the date of temporary rates (July 1, 2010).

Our interstate natural gas transmission pipeline recently received approval from the Federal Energy Regulatory Commission of an uncontested rate settlement. The rate settlement resolved all matters in the rate proceeding, and provides for an increase of approximately $1.7 million in annual revenue, based on new gas transportation rates effective as of January 1, 2011.

In January 2011, we filed base rate cases for our Massachusetts gas and electric distribution utility. We requested $7.1 million of rate relief for our electric division and $4.4 million of base rate relief for our natural gas division. In the electric division rate case, we included a proposal to lower our existing Transition Charge and extend the recovery of industry restructuring related costs to completely offset the requested increase in electric base revenue, so that our electric customers will see no increase in their total bill. We are also seeking approval of a revenue decoupling proposal for both the electric and gas divisions, similar to those already approved for other utilities in Massachusetts. Our revenue decoupling proposal is intended to facilitate the achievement of important public policy objectives of fostering energy efficiency, conservation, and security, as well as protecting the environment. We expect to obtain a final rate order in this proceeding for new rates effective in August 2011.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire **(State or other jurisdiction of incorporation or organization)**	**02-0381573** **(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire **(Address of principal executive offices)**	**03842-1720** **(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Based on the closing price of June 30, 2010, the aggregate market value of common stock held by non-affiliates of the registrant was $224,000,571.

The number of common shares outstanding of the registrant was 10,891,621 as of February 1, 2011.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011 are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2010
Table of Contents

[THIS PAGE INTENTIONALLY LEFT BLANK]

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly-owned subsidiaries of Unitil:

Company Name	State and Year of Organization	Principal Business
Unitil Energy Systems, Inc. (Unitil Energy)	NH - 1901	Electric Distribution Utility
Fitchburg Gas and Electric Light Company (Fitchburg)	MA - 1852	Electric & Gas Distribution Utility
Northern Utilities, Inc. (Northern Utilities)	NH - 1979	Natural Gas Distribution Utility
Granite State Gas Transmission, Inc. (Granite State)	NH - 1955	Natural Gas Transmission Pipeline
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-regulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territories in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities: i) Unitil Energy, which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the capital city of Concord, ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts, and iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland, which is the largest city in northern New England. In addition, Unitil is the parent company of Granite State, an interstate natural gas transmission pipeline company that provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory. Together, Unitil's three distribution utilities serve approximately 100,900 electric customers and 70,800 natural gas customers.

Unitil's distribution utilities had an investment in Net Utility Plant of $476.5 million at December 31, 2010. Unitil's total operating revenue was $358.4 million in 2010. Substantially all of Unitil's operating revenue is derived from regulated distribution utility operations.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy in 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are indirect subsidiaries that are wholly-owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers primarily in the northeastern United States.

OPERATIONS

Gas Operations

Unitil's Gas Operations include gas distribution utility operations and interstate gas transmission pipeline operations, discussed below. Revenue from Unitil's gas operations was $150.1 million for 2010, which represent about 42% of Unitil's total operating revenue. In 2008, the Company significantly expanded its gas operations by acquiring Northern Utilities and Granite State.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate natural gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement (the Acquisitions). Bay State is a wholly-owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt (see "Liquidity, Commitments and Capital Requirements" section in Part II, Item 7 below). The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features (See Note 6 to the accompanying Consolidated Financial Statements for additional information on these settlement agreements).

Gas Distribution Utility Operations

Unitil's natural gas distribution operations are conducted through two of the Company's operating utilities, Northern Utilities and Fitchburg. The primary business of Unitil's natural gas utility operations is the local distribution of natural gas to customers in its service territory in New Hampshire, Massachusetts and Maine. As a result of a restructuring of the gas utility industry in New Hampshire, Massachusetts and Maine, Fitchburg's residential and commercial and industrial (C&I) customers and Northern Utilities' C&I customers have the opportunity to purchase their natural gas supplies from third-party energy supply vendors. Most customers, however, continue to purchase such supplies through Northern Utilities and Fitchburg under regulated rates and tariffs. Northern Utilities and Fitchburg purchase natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis through reconciling rate mechanisms that are periodically adjusted.

Natural gas is supplied and distributed by Northern Utilities to approximately 55,500 customers in 44 New Hampshire and southern Maine communities, from Plaistow, New Hampshire in the south to the city of Portland, Maine and then extending to Lewiston-Auburn, Maine in the north. Northern Utilities has a diversified customer base both in Maine and New Hampshire. Commercial businesses include healthcare, education, government and retail. Northern Utilities' industrial base includes manufacturers in the industries of auto, housing, rubber, printing, textile, pharmaceutical, electronics, wires and food production as well as a military installation. Northern Utilities' 2010 gas operating revenue was $116.2 million, of which approximately 39.0% was derived from residential firm sales and 61.0% from commercial/industrial firm sales.

Natural gas is supplied and distributed by Fitchburg to approximately 15,300 customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. Fitchburg's 2010 gas operating revenue was $29.9 million, of which approximately 51% was derived from residential firm sales and 49.0% from commercial/industrial firm sales.

Gas Transmission Pipeline Operations

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State

provides Northern Utilities with interconnection to major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State had operating revenue of $4.0 million for 2010. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and to third-party marketers.

Electric Distribution Utility Operations

Unitil's electric distribution operations are conducted through two of the Company's utilities, Unitil Energy and Fitchburg. Revenue from Unitil's electric utility operations was $203.7 million for 2010, which represents about 57% of Unitil's total operating revenue.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its service territory in New Hampshire and Massachusetts. As a result of the implementation of choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The distribution utilities continue to deliver that supply of electricity over their distribution systems. Both Unitil Energy and Fitchburg supply electricity to those customers who do not obtain their supply from third-party suppliers, with the approved costs associated with electricity supplied by the distribution utilities being recovered on a pass-through basis under periodically-adjusted rates.

Unitil Energy distributes electricity to approximately 72,700 customers in New Hampshire in the capital city of Concord as well as parts of 12 surrounding towns and all or part of 18 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. Unitil Energy's service territory consists of approximately 408 square miles. In addition, Unitil Energy's service territory encompasses retail trading and recreation centers for the central and southeastern parts and includes the Hampton Beach recreational area. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics, healthcare and education. Unitil Energy's 2010 electric operating revenue was $140.7 million, of which approximately 54.0% was derived from residential sales and 46.0% from commercial/industrial sales.

Fitchburg is engaged in the distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts. Fitchburg's service territory encompasses approximately 170 square miles. Electricity is supplied and distributed by Fitchburg to approximately 28,200 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries and education. Fitchburg's 2010 electric operating revenue was $63.0 million, of which approximately 53.0% was derived from residential sales and 47.0% from commercial/industrial sales.

Seasonality

As a result of the acquisitions of Northern Utilities and Granite State in 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in all reporting periods presented. In particular, the Company's results will reflect the seasonal nature of the natural gas distribution business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher due to heating-related requirements, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours. Unitil Energy, Fitchburg and Northern Utilities are not dependent on a single customer or a few customers for their electric and natural gas sales.

Non-regulated and Other Non-Utility Operations

Unitil's non-regulated operations are conducted through Usource, a subsidiary of Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's non-regulated operations was $4.6 million in 2010.

The results of Unitil's other non-utility subsidiaries, Unitil Service and Unitil Realty, and the holding company are included in the Company's consolidated results of operations. The results of these non-utility operations are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and are reported, after intercompany eliminations, in Other segment income (for segment information, see Part II, Item 8, Note 9 herein).

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 with regard to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, with regard to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and Maine Public Utilities Commission (MPUC). Granite State, Unitil's interstate natural gas transmission pipeline, is subject to regulation by the FERC with regard to its rates and operations. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third-party energy supply vendors. Most customers, however, continue to purchase such supplies through the distribution utilities under regulated energy rates and tariffs. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual approved costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

Rate Case Activity

On April 15, 2010, Unitil Energy filed for a distribution base rate increase of $10.1 million. The Company's filing also included a proposed long-term rate plan establishing step adjustments for future utility plant investments and enhanced reliability and vegetation management programs. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy of $5.2 million effective July 1, 2010. Once permanent rates are approved by the NHPUC, they will be reconciled to the date temporary rates were ordered. The Company is currently engaged in settlement proceedings regarding the permanent rate level and a long-term rate plan. A hearing in this matter is scheduled for early February 2011.

On November 30, 2010 the Company's interstate natural gas transmission pipeline, Granite State, filed a rate settlement agreement, which provides for an increase of approximately $1.7 million in annual revenue effective January 1, 2011. This settlement agreement was approved by the FERC on January 31, 2011.

On January 14, 2011, the Company's Massachusetts operating utility, Fitchburg, filed a comprehensive revenue decoupling proposal and a request for distribution rate increases of $7.1 million for its electric division and $4.4 million of its gas division. The Company's filing also includes a rate-impact mitigation alternative for the electric division that would offset the distribution revenue increase through a corresponding decrease in Fitchburg's Transition Charge. The Transition Charge is the means by which Fitchburg recovers its power supply-related stranded costs and other restructuring-related regulatory assets. Any offsetting decrease in the Transition Charge would allow for the recovery of the restructuring related stranded costs over an extended term. The Company's revenue decoupling proposal is modeled closely on decoupling proposals already approved by the MDPU for other utilities operating in the Commonwealth of Massachusetts and is intended to align the Company's interests with important public policy objectives concerning energy efficiency, energy reliability, national energy security and protecting the environment. The MDPU issued an order suspending and deferring the use of the rates until August 2, 2011, pending an investigation and analysis of the Company's filing.

Northern Utilities, the Company's gas distribution utility operating in New Hampshire and Maine, is currently planning to file base rate cases for both its New Hampshire and Maine divisions in the second quarter of 2011. The Company will announce the amount of the requested rate increases and other related information after the filing of the distribution base rate cases.

Also see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Rates and Regulation.

NATURAL GAS SUPPLY

Unitil manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and C&I customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors. Many large and some medium C&I customers purchase their supplies from third-party suppliers, while most of Fitchburg's residential and small C&I customers continue to purchase their supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern Utilities purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern Utilities arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of LNG, to truck supplies to each storage facility within Northern Utilities' service territory.

Northern Utilities has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns an LNG storage and vaporization facility. This plant is used principally during peak load periods to augment the supply of pipeline natural gas.

ELECTRIC POWER SUPPLY

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third-party energy suppliers. As of December 2010, 104 or 70% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 87% of Unitil's largest Massachusetts customers, representing 36% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential, small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two two-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

In connection with the restructuring of the electric industry, Unitil Power, Unitil Energy and Fitchburg divested and sold substantially their power supply portfolios consisting of long-term power supply contracts and ownership interests in generation assets. Unitil Power, Unitil Energy and Fitchburg recover in their rates all the costs associated with this divestiture and sale and have secured regulatory approval from the FERC, NHPUC and MDPU, respectively, for the recovery of stranded costs, including long term contract buyout agreements, and other restructuring-related regulatory assets. The companies have a continuing obligation to submit regulatory filings that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

ENVIRONMENTAL MATTERS

Unitil's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed. Also, see Note 6 to the accompanying consolidated financial statements.

Fitchburg recovers the environmental response costs incurred at this former MGP site in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. In January 2011, Fitchburg settled with the remaining insurance carriers for approximately $2.0 million and expects to receive these payments in the first quarter of 2011. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are shared equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Also, see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES

As of December 31, 2010, the Company and its subsidiaries had 437 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2010, 150 of the Company's employees were represented by labor unions. These employees are covered by four separate collective bargaining agreements which expire on March 31, 2012, May 31, 2012, May 31, 2013 and June 5, 2014. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is *www.unitil.com*. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the New York Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 3, 2011:

Name	Age	Position
Robert G. Schoenberger	60	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	51	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	48	Senior Vice President and Chief Operating Officer
Laurence M. Brock	57	Controller and Chief Accounting Officer
Todd R. Black	46	Senior Vice President, External Affairs and Customer Relations, Unitil Service
George R. Gantz	59	Senior Vice President, Distributed Energy Resources, Unitil Service
George E. Long, Jr.	54	Vice President, Administration, Unitil Service
Sandra L. Whitney	47	Corporate Secretary
William D. Adams	63	Director
Dr. Robert V. Antonucci	65	Director
David P. Brownell	67	Director
Michael J. Dalton	70	Director
Albert H. Elfner, III	66	Director
Edward F. Godfrey	61	Director
Michael B. Green	61	Director
Eben S. Moulton	64	Director
M. Brian O'Shaughnessy	67	Director
Dr. Sarah P. Voll	68	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board of Directors and Chief Executive Officer since 1997, as well as President since 2003. Prior to his employment with Unitil, Mr. Schoenberger was president and chief operating officer of the New York Power Authority (a state-owned utility) from 1993 until 1997. Mr. Schoenberger has also served as a director of Satcon Technology Corporation, Boston, Massachusetts (a company that develops innovative power conversion solutions for the renewable power industry) since 2007. Mr. Schoenberger also serves as chairman of the Tocqueville Society of the Greater Seacoast (New Hampshire) United Way. Mr. Schoenberger formerly served as chairman and trustee of Exeter Health Resources, Exeter, New Hampshire, from 1998 until 2009, and as a director of the Southwest Power Pool from 2003 until 2005.

Mark H. Collin has been Unitil's Senior Vice President and Chief Financial Officer since February 2003. Mr. Collin has also served as Treasurer since 1998. Mr. Collin joined Unitil in 1988, and served as Vice President of Finance from 1995 until 2003.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President and Chief Operating Officer since June 2005. Mr. Meissner served as Senior Vice President, Operations, from February 2003 until June 2005. Mr. Meissner joined Unitil in 1994 and served as Director of Engineering from 1998 until 2003.

George R. Gantz has been Unitil's Senior Vice President, Distributed Energy Resources, Unitil Service, since September 2009. Mr. Gantz joined Unitil in 1983 and served as Senior Vice President, Communication and Regulation from 1994 until 2003, and Senior Vice President, Customer Services and Communications from 2003 until 2009.

Todd R. Black has been Unitil's Senior Vice President, External Affairs and Customer Relations, Unitil Service, since September 2009. Mr. Black joined Unitil in 1998 and served as Vice President, Sales and Marketing, for Usource from 1998 until 2003, and President of Usource from 2003 until 2009.

Laurence M. Brock has been Unitil's Controller and Chief Accounting Officer since June 2005. Mr. Brock joined Unitil in 1995 as Vice President and Controller, and is a certified public accountant in the state of New Hampshire.

George E. Long, Jr. has been Unitil's Vice President, Administration, Unitil Service, since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources, from 1998 until 2003.

Sandra L. Whitney has been Unitil's Corporate Secretary and secretary of our Board of Directors since February 2003. Ms. Whitney joined Unitil in 1990 and also serves as the Corporate Secretary of Unitil's subsidiary companies.

William D. Adams has been a member of Unitil's Board of Directors since 2009. Mr. Adams has been the president of Colby College in Waterville, Maine, since 2000. Mr. Adams also serves on the board of trustees of Colby College. Prior to going to Colby, Mr. Adams served as president of Bucknell University in Pennsylvania from 1995 until 2000. Prior to leading Bucknell, he served as vice president and secretary of Wesleyan University in Connecticut. Mr. Adams also served as coordinator of the Great Works in Western Culture program at Stanford University and taught political philosophy at the University of North Carolina at Chapel Hill and Santa Clara University. Mr. Adams has served on the board of directors of Wittenberg University since 2007, and Maine Public Broadcasting Corporation since 2002. Mr. Adams was also a director of Maine General Health from 2002 to 2010.

Dr. Robert V. Antonucci has been a member of Unitil's Board of Directors since 2004. Dr. Antonucci has been the president of Fitchburg State University (FSU) in Fitchburg, Massachusetts, since 2003. Prior to his employment with FSU, Dr. Antonucci was president of the School Group of Riverdeep, Inc., San Francisco, California, from 2001 until 2003 and president and chief executive officer of Harcourt Learning Direct and Harcourt Online College, Chestnut Hill, Massachusetts from 1998 until 2001. Dr. Antonucci also served as the commissioner of education for the Commonwealth of Massachusetts from 1992 until 1998. In addition, Dr. Antonucci has served as a trustee of Eastern Bank since 1988. Dr. Antonucci also serves as a director of the North Central Massachusetts Chamber of Commerce and a director of the North Central Massachusetts United Way.

David P. Brownell has been a member of Unitil's Board of Directors since 2001. Mr. Brownell has been a retired senior vice president of Tyco International Ltd. (Tyco) (a diversified global manufacturing and service company), Portsmouth, New Hampshire, since 2003. Mr. Brownell had been with Tyco since 1984. Mr. Brownell was also interim president of the University of New Hampshire (UNH) Foundation, former vice chairman of the board of UNH Foundation, former volunteer board president of the United Way of the Greater Seacoast, and a former board member of the New Hampshire Junior Achievement Advisory Council.

Michael J. Dalton has been a member of Unitil's Board of Directors since 1984. Mr. Dalton retired as President and Chief Operating Officer of Unitil in 2003. Mr. Dalton is a member of the Industrial Advisory Council of the UNH College of Engineering and Physical Science and Vice President of the Alumni Society of the College of Engineering and Physical Science. In addition, Mr. Dalton also serves as a mentor with the UNH Pathways Mentorship Program. Mr. Dalton was formerly a director of the New England Gas Association, the Electric Council of New England, the UNH Foundation, the UNH Alumni Association, and the UNH President's Council.

Albert H. Elfner, III has been a member of Unitil's Board of Directors since 1999. Mr. Elfner was the chairman of Evergreen Investment Management Company, Boston, Massachusetts, from 1994 until 1999 and its chief executive officer from 1995 until 1999. Mr. Elfner is also a director of Main Street America Insurance Company (Main Street), Jacksonville, Florida, as well as chairman of the Main Street finance committee.

Edward F. Godfrey has been a member of Unitil's Board of Directors since 2002. Mr. Godfrey was the executive vice president and chief operating officer of Keystone Investments, Incorporated (Keystone), Boston, Massachusetts, from 1997 until 1998. Mr. Godfrey was senior vice president, chief financial officer and treasurer of Keystone from 1988 until 1996. Mr. Godfrey is also a director of Vector Fleet Management, LLC, Charlotte, North Carolina, since 2006.

Michael B. Green has been a member of Unitil's Board of Directors since 2001. Mr. Green has been the president and chief executive officer of Capital Region Health Care and Concord Hospital, Concord, New Hampshire, since 1992. Mr. Green is also a member of the adjunct faculty, Dartmouth Medical School, Dartmouth College, Hanover, New Hampshire. In addition, Mr. Green currently serves on the board of the Foundation for Healthy Communities, is a director of the New Hampshire Hospital Association, a director of Concord General Mutual Insurance Company, and a director of Merrimack County Savings Bank (Merrimack), including membership on Merrimack's investment and audit committees.

Eben S. Moulton has been a member of Unitil's Board of Directors since 2000. Mr. Moulton has been the managing partner of Seacoast Capital Corporation, Danvers, Massachusetts, (a private investment company) since 1995. Mr. Moulton is also a director of IEC Electronics Corp. (a company that provides electronic manufacturing services to advanced technology companies), Newark, New York, and a director of six private companies.

M. Brian O'Shaughnessy has been a member of Unitil's Board of Directors since 1998. Mr. O'Shaughnessy has been the chairman of the board of Revere Copper Products, Inc. (Revere), Rome, New York, since 1988. Mr. O'Shaughnessy also served as chief executive officer and president of Revere from 1988 until 2007. Mr. O'Shaughnessy also serves on the Board of Directors and as the chief co-chair of the Coalition for a Prosperous America, three copper industry trade associations, three manufacturing associations in New York State regarding energy-related issues, and the Economic Development Growth Enterprise of Mohawk Valley.

Dr. Sarah P. Voll has been a member of Unitil's Board of Directors since 2003. Dr. Voll retired in 2007 as vice president from National Economic Research Associates, Inc. (NERA), Washington, District of Columbia, a firm of consulting economists specializing in industrial and financial economics, and currently serves as a special consultant to NERA. Dr. Voll had been with NERA in the position of vice president since 1999, and in the position of senior consultant from 1996 until 1999. Prior to her employment with NERA, Dr. Voll was a staff member at the NHPUC from 1980 until 1996.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 21, 2011, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of common stock, administration of the Dividend Reinvestment and Stock Purchase Plan, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Computershare
P.O. Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

Investor Relations

For information about the Company, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investors page at *www.unitil.com*; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available to Holders of Record

If a shareholder's shares of common stock are registered directly in the shareholder's name with the Company's transfer agent, the shareholder is considered a holder of record of the shares. The following services and programs are available to shareholders of record:

- Internet Account Access is available at *www.computershare.com*.
- Dividend Reinvestment and Stock Purchase Plan:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Direct Registration:

  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

The Company is subject to comprehensive regulation, which could impact the rates it is able to charge, its authorized rate of return and its ability to recover costs. This could adversely affect the Company's financial condition or results of operations. In addition, certain regulatory authorities have the power to impose finance penalties and other sanctions on the Company, which could adversely affect the Company's financial condition or results of operations.

The Company is subject to comprehensive regulation by federal regulatory authorities (including the FERC) and state regulatory authorities (including the NHPUC, MDPU and MPUC). These authorities regulate many aspects of the Company's operations, including the rates that the Company can charge customers, the Company's authorized rates of return, the Company's ability to recover costs from its customers, construction and maintenance of the Company's facilities, the Company's safety protocols and procedures, the Company's ability to issue securities, the Company's accounting matters, and transactions between the Company and its affiliates. The Company is unable to predict the impact on its financial condition or results of operations from the regulatory activities of any of these regulatory authorities. Also, changes in regulations or the imposition of additional regulations could adversely affect the Company's financial condition or results of operations.

The Company's ability to obtain rate adjustments to maintain its current authorized rates of return depends upon action by regulatory authorities under applicable statutes, rules and regulations. These regulatory authorities are authorized to leave the Company's rates unchanged, to grant increases in such rates or to order decreases in such rates. The Company may be unable to obtain favorable rate adjustments or to maintain its current authorized rates of return, which could adversely affect its financial condition or results of operations.

Regulatory authorities also have authority with respect to the Company's ability to recover its electricity and natural gas supply costs, as incurred by Unitil Power, Unitil Energy, Fitchburg, and Northern Utilities. If the Company is unable to recover a significant amount of these costs, or if the Company's recovery of these costs is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

In addition, certain regulatory authorities have the power to impose financial penalties and other sanctions on the Company if the Company is found to have violated statutes, rules or regulations governing its utility operations. This could adversely affect the Company's financial condition or results of operations. Please see (i) the section entitled *Regulatory Matters—Fitchburg—Gas Operations* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) the section entitled *Regulatory Matters—Fitchburg—Gas* Operations in Note 6 (Commitments and Contingencies) to the accompanying Consolidated Financial Statements.

Severe storms have struck, and may strike, the New England region, causing extensive damage to the Company's utility operations and the loss of service to significant numbers of the Company's customers. If the Company is unable to recover a significant amount of storm costs in its rates, or if the Company's recovery of storm costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

Please see (i) the sections entitled *Regulatory Matters—Major Wind Storm* and *Regulatory Matters—Major Ice Storm* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) the sections entitled *Regulatory Matters—Major Wind Storm* and *Regulatory Matters—Major Ice Storm* in Note 6 (Commitments and Contingencies) to the accompanying Consolidated Financial Statements.

As a result of electric industry restructuring, the Company has a significant amount of stranded electric generation and power supply related supply costs. If the Company is unable to recover a significant amount of stranded costs in its rates, or if the Company's recovery of stranded costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

The stranded electric generation and power supply related supply costs resulting from the implementation of electric industry restructuring mandated by the states of New Hampshire and Massachusetts are recovered by the Company on a pass-through basis through periodically reconciled rates. Any unrecovered balance of stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

Substantially all of the Company's stranded costs relate to (i) Unitil Power's long-term power purchase agreements (which Unitil Power divested under long-term contract buyout agreements) and (ii) Fitchburg's formerly owned generation assets and purchase power agreements (which Fitchburg divested under a long-term contract buy-out agreement). Unitil Power made the final payment on its long-term contract buyout agreements in October 2010, which ended its obligations in the underlying purchase power contracts. As a result, in accordance with its retail stranded cost recovery rates, substantially all of Unitil Energy's stranded costs are projected to be fully recovered by July 31, 2011. Because Fitchburg continues to remain ultimately responsible for purchase power payments underlying its long-term buyout agreements, Fitchburg could incur additional stranded costs were they required to resell such divested entitlements prior to the end of their term for amounts less than the amounts agreed to under the existing long-term buyout agreements. The Company expects that any such additional stranded costs would be recovered from its customers, however such recovery would require approval from the MDPU, the receipt of which cannot be assured. If the Company is unable to recover a significant amount of such stranded costs in its rates, or if the Company's recovery of such stranded costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected. Please see (i) the section entitled *Regulatory Matters—Overview (Unitil Energy, Fitchburg, and Northern Utilities)* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) the section entitled *Regulatory Matters—Overview (Unitil Energy, Fitchburg, and Northern Utilities)* in Note 6 (Commitments and Contingencies) to the accompanying Consolidated Financial Statements.

The Company's electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may adversely affect the Company's customers and correspondingly the Company's financial condition or results of operations.

The Company's business is influenced by the economic activity within its service territory. The level of economic activity in the Company's electric and natural gas distribution service territory directly affects the Company's business. As a result, adverse changes in the economy may adversely affect the Company's financial condition or results or operations.

The Company may not be able to obtain financing, or may not be able to obtain financing on acceptable terms, which could adversely affect the Company's financial condition or results of operations.

The Company requires capital to fund utility plant additions, working capital and other utility expenditures. While the Company derives the capital necessary to meet these requirements primarily from internally-generated funds, the Company supplements internally generated funds by incurring short-term debt under its current credit facility, as needed. If the lending counterparties under the Company's current credit facility are unwilling or unable to meet their funding obligations, then the Company may be unable to, or limited in its ability to, incur short-term debt under its credit facility. This could hinder or prevent the Company from meeting its current and future capital needs, which could correspondingly adversely affect the Company's financial condition or results or operations.

Also, from time to time, the Company repays portions of its short-term debt with the proceeds it receives from long-term debt financings or equity financings. General economic conditions and the Company's operating and financial performance could negatively affect the Company's ability to obtain such financings and the terms of such financings, which could correspondingly adversely affect the Company's financial condition or results or operations.

Declines in the valuation of capital markets could require the Company to make substantial cash contributions to cover its pension obligations. If the Company is unable to recover a significant amount of pension obligation costs in its rates, or if the Company's recovery of pension obligation costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

Please see (i) the section entitled *Critical Accounting Policies—Pension Benefit Obligations* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) Note 10 (Retirement Benefit Plans) to the accompanying Consolidated Financial Statements.

Increases in interest rates could increase the Company's interest expense and adversely affect the Company's financial condition or results of operations.

The Company and its utility subsidiaries have ongoing capital expenditure and cash funding requirements, which they frequently fund by issuing short-term debt and long-term debt.

The Company's short-term debt revolving credit facility typically has variable interest rates. Therefore, an increase or decrease in interest rates will increase or decrease the Company's interest expense associated with its revolving credit facility. An increase in the Company's interest expense could adversely affect the Company's financial condition or results of operations. As of December 31, 2010, the Company had approximately $66.8 million in short-term debt outstanding under its revolving credit facility.

The Company's long-term debt typically has fixed interest rates. Therefore, changes in interest rates will not affect the Company's interest expense associated with its presently outstanding fixed rate long-term debt. However, an increase or decrease in interest rates may increase or decrease the Company's interest expense associated with any new fixed rate long-term debt issued by the Company, which could adversely affect the Company's financial condition or results of operations. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

In addition, the Company may need to use a significant portion of its cash flow to repay its short-term debt and long-term debt, which would limit the amount of cash it has available for working capital, capital expenditures and other general corporate purposes and could adversely affect its financial condition or results of operations.

The terms of the Company's and its subsidiaries' indebtedness restrict the Company's business operations (including their ability to incur material amounts of additional indebtedness), which could adversely affect the Company's financial condition or results or operations.

See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

A significant amount of the Company's sales are temperature sensitive. Because of this, mild winter and summer temperatures could decrease the Company's sales, which could adversely affect the Company's financial condition or results or operations. Also, the Company's sales may vary from year to year depending on weather conditions, and the Company's results of operations generally reflect seasonality.

The Company estimates that approximately 50% of its annual natural gas sales are temperature sensitive. Therefore, mild winter temperatures could decrease the amount of natural gas sold by the Company, which could adversely affect the Company's financial condition or results of operations. The Company's electric sales also are temperature sensitive, but less so than its natural gas sales. The highest usage of electricity typically occurs in the summer months (due to air conditioning demand) and the winter months (due to heating-related and lighting requirements). Therefore, mild summer temperatures and mild winter temperatures could decrease the amount of electricity sold by the Company, which could adversely affect the Company's financial condition and results of operations. Also, because of this temperature sensitivity, sales by the Company's distribution utilities vary from year to year, depending on weather conditions.

In addition, the Company's results of operations generally reflect seasonality. In particular, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher (due to heating-related requirements), and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Long-term global climate change could adversely affect customer demand or cause extreme weather events that could disrupt the Company's electric and natural gas distribution services.

Milder winter and summer temperatures due to long-term global climate change may cause a decrease in the amount of natural gas and electricity sold by the Company, which could correspondingly adversely affect the Company's financial condition and results or operations. Conversely, colder winter temperatures and warmer summer temperatures due to long-term global climate change may cause an increase in the amount of natural gas and electricity sold by the Company.

In addition, extreme weather events (such as hurricanes and severe winter storms) related to long-term global climate change may damage facilities or result in increased service interruptions and outages and increase the Company's operations and maintenance costs. If the Company is unable to recover a significant amount of such costs in its rates, or if the Company's recovery of such costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

The Company is unable to predict the impacts on its financial condition and results or operations due to changes in weather related to long-term global climate change.

Unitil is a public utility holding company and has no operating income of its own. The Company's ability to pay dividends on its common stock is dependent on dividends and other payments received from its subsidiaries and on factors directly affecting Unitil, the parent corporation. The Company cannot assure you that its current annual dividend will be paid in the future.

The ability of the Company's subsidiaries to pay dividends or make distributions to Unitil depends on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of the Company's subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by the Company's subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of the Company's subsidiaries and that may be contained in future debt agreements of the Company's subsidiaries, if any; and
- limitations that may be imposed by New Hampshire, Massachusetts and Maine state regulatory agencies.

In addition, before the Company can pay dividends on its common stock, it has to satisfy its debt obligations and comply with any statutory or contractual limitations.

The Company's current annual dividend is $1.38 per share of common stock, payable quarterly. However, the Company's Board of Directors reviews Unitil's dividend policy periodically in light of the factors referred to above, and the Company cannot assure the amount of dividends, if any, that may be paid in the future.

The Company's electric and natural gas distribution activities (including storing natural gas and supplemental gas supplies) involve numerous hazards and operating risks that may result in accidents and other operating risks and costs. Any such accident or costs could adversely affect the Company's financial position and results of operations.

Inherent in the Company's electric and natural gas distribution activities are a variety of hazards and operating risks, including leaks, explosions, electrocutions and mechanical problems. These hazards and risks could result in loss of human life, significant damage to property, environmental pollution, damage to natural resources and impairment of the Company's operations, which could adversely affect the Company's financial position and results of operations.

The Company maintains insurance against some, but not all, of these risks and losses in accordance with customary industry practice. The location of pipelines, storage facilities and electric distribution equipment near populated areas (including residential areas, commercial business centers and industrial sites) could increase the level of damages associated with these risks. The occurrence of any of these events could adversely affect the Company's financial position or results of operations.

The Company's business is subject to environmental regulation in all jurisdictions in which it operates and its costs of compliance are significant. New or changes to existing environmental regulation, including related to climate change or greenhouse gas emissions, and the incurrence of environmental liabilities could adversely affect the Company's financial condition or results of operations.

The Company's utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources, and the health and safety of the Company's employees. The Company's utility operations also may be subject to new and emerging federal, state and local legislative and regulatory initiatives related to climate change or greenhouse gas emissions including the U.S. Environmental Protection Agency's mandatory greenhouse gas reporting rule. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties and other sanctions; imposition of remedial requirements; and issuance of injunctions to ensure future compliance. Liability under certain environmental laws and regulations is strict, joint and several in nature. Although the Company believes it is in material compliance with all applicable environmental and safety laws and regulations, there can be no assurance that the Company will not incur significant costs and liabilities in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, including those related to climate change or greenhouse gas emissions, could result in increased environmental compliance costs.

Catastrophic events could adversely affect the Company's financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could inhibit the Company's ability to provide electric or natural gas distribution services to its customers for an extended period, which could adversely affect the Company's financial condition and results of operations.

The Company's business could be adversely affected if it is unable to retain its existing customers or attract new customers.

The success of the Company's business depends, in part, on its ability to maintain and increase its customer base. The Company's failure to maintain or increase its customer base could adversely affect its financial condition and results of operations.

The Company's energy brokering customers may default in their performance under multi-year energy brokering contracts, which could adversely affect the Company's financial condition and results of operations.

The Company's non-regulated energy brokering business provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenues from this business are primarily derived from brokering fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts. The Company's customers may default in their performance under multi-year energy brokering contracts, which could adversely affect the Company's financial condition and results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2010, Unitil owned, through its distribution utilities, three utility operation centers, approximately 2,181 pole miles of local transmission and distribution overhead electric lines and 549 cable miles of underground electric distribution lines, along with 49 electric substations, including four mobile electric substations. Our natural gas operations property includes two liquid propane gas plants, two liquid natural gas plants and 1,280 miles of underground gas mains. In addition, our real estate subsidiary, Unitil Realty, owns our corporate headquarters building and the 12 acres of land on which it is located.

Unitil Energy owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. Unitil Energy's 30 electric distribution substations, including a 5,000 kilovolt ampere (kVA) and a 10,500 kVA mobile substation, constitute 219,002 kVA of capacity, which excludes capacity of spare transformers, for the transformation of electric power from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by Unitil Energy or land occupied by Unitil Energy pursuant to perpetual easements.

Unitil Energy has a total of approximately 1,619 pole miles of local transmission and distribution overhead electric lines and a total of 368 cable miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Unitil Energy without objection by the owners. In the case of certain distribution lines, Unitil Energy owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

The physical utility properties of Unitil Energy, with certain exceptions, and its franchises are subject to its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of Unitil Energy are outstanding.

Fitchburg's electric properties consist principally of 562 pole miles of local transmission and distribution overhead electric lines, 181 cable miles of underground electric distribution lines and 19 transmission and distribution stations (including two mobile electric substations). The capacity of these substations totals 441,650 kVA, which excludes capacity of spare transformers.

Fitchburg owns a liquid propane gas plant and a liquid natural gas plant, both of which are located on land owned by Fitchburg. Fitchburg also has 263 miles of underground steel, cast iron and plastic gas mains.

Fitchburg's electric substations, with minor exceptions, are located on land owned by Fitchburg or occupied by Fitchburg pursuant to perpetual easements. Fitchburg's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Fitchburg without objection by the owners. Fitchburg leases its distribution operations center located in Fitchburg, Massachusetts.

Northern Utilities’ distribution system is comprised of 1,017 miles of gas mains and 38,450 service pipes. The gas mains are primarily made up of polyethylene plastic (69%), coated and wrapped cathodically protected steel (19%), cast/wrought iron (7%), and unprotected bare and coated steel (5%).

Northern Utilities’ New Hampshire division serving 21 communities has 499 miles of distribution gas mains and 20,844 service pipes. Northern Utilities’ Maine division serving 23 communities has 518 miles of distribution and 17,606 service pipes. Northern Utilities also owns a liquid propane gas plant and a LNG storage and vaporization facility.

Granite State is a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline located primarily in Maine and New Hampshire.

The Company believes that its facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company’s financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg’s service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company’s Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2011. The Company continues to believe the suit is without merit and will defend itself vigorously.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's common stock is listed on the New York Stock Exchange under the symbol "UTL". As of December 31, 2010, there were 1,597 shareholders of record.

Common Stock Data

Dividends per Common Share	2010	2009
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2010		2009	
Price Range of Common Stock	High/Ask	Low/Bid	High/Ask	Low/Bid
1st Quarter	**$24.40**	**$20.46**	$20.75	$17.50
2nd Quarter	**$24.36**	**$19.28**	$22.83	$18.76
3rd Quarter	**$22.99**	**$20.55**	$23.26	$20.19
4th Quarter	**$23.49**	**$21.22**	$23.67	$19.31

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

Equity Compensation Plan Benefit Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
Restricted Stock Plan (1)	—	N/A	62,790
Equity compensation plans not approved by security holders			
1998 Option Plan (2)	33,000	$25.88	—
Total	33,000	$25.88	62,790

NOTES: (also see Note 3 to the accompanying Consolidated Financial Statements)

(1) The Restricted Stock Plan (the Plan) was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006; 9,020 shares of restricted stock were awarded to Plan participants in February 2007; 15,540 shares of restricted stock were awarded to Plan participants in February 2008; 32,260 shares of restricted stock were awarded to Plan participants in February 2009. 12,520 shares of restricted stock were awarded to Plan participants in February 2010.

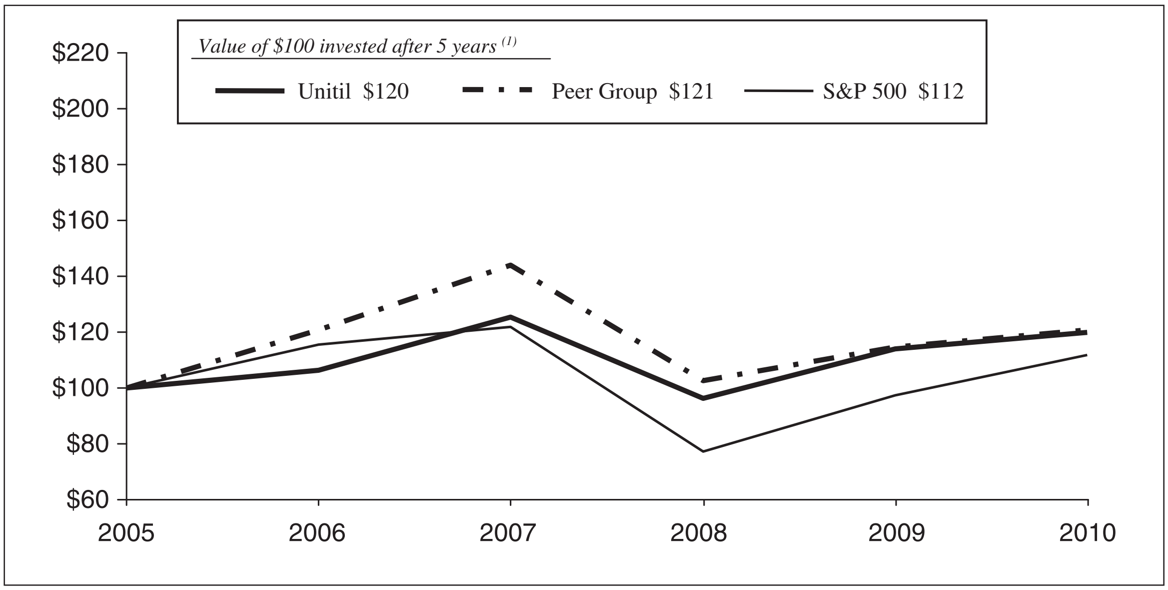
(2) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange (the exchange upon which the Company was then listed) rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the 1998 Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the 1998 Option Plan were

deregistered with the Securities and Exchange Commission. Since the plan's termination by Board of Directors, no further grants of options were made thereunder. The remaining 33,000 options expired on January 16, 2011 without being exercised.

Stock Performance Graph

The following graph compares Unitil Corporation's cumulative stockholder return since December 31, 2005 with the Peer Group index, comprised of the S&P Utility Index, and the S&P 500 index. The graph assumes that the value of the investment in the Company's common stock and each index (including reinvestment of dividends) was $100 on December 31, 2005.

Comparative Five-Year Total Returns



NOTE:

(1) The graph above assumes $100 invested on December 31, 2005, in each category and the reinvestment of all dividends during the five-year period. The Peer Group is comprised of the S&P Utility Index.

Unregistered Sales of Equity Securities and Uses of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2010.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 25, 2010, the Company will periodically repurchase shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. There is no pool or maximum number of shares related to these purchases; however, the trading plan will automatically terminate when $80,700 in value of shares have been purchased, or, if sooner, on March 25, 2011.

The Company may suspend or terminate this trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
10/1/10 – 10/31/10	—	—	—
11/1/10 – 11/30/10	—	—	—
12/1/10 – 12/31/10	2,497	$22.98	2,497
Total	2,497	$22.98	2,497

Item 6. Selected Financial Data

For the Years Ended December 31,	2010	2009	2008	2007	2006
(all data in millions except shares, % and per share data) [1]					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 358.4**	$ 367.0	$ 288.2	$ 262.9	$ 260.9
Operating Income	**28.0**	26.1	20.5	18.5	15.8
Other Non-operating Expense	**0.3**	0.3	0.3	0.2	—
Income Before Interest Expense	**27.7**	25.8	20.2	18.3	15.8
Interest Expense, net	**18.1**	15.8	10.5	9.6	7.8
Net Income	**9.6**	10.0	9.7	8.7	8.0
Dividends on Preferred Stock	**0.1**	0.1	0.1	0.1	0.1
Earnings Applicable to Common Shareholders	**$ 9.5**	$ 9.9	$ 9.6	$ 8.6	$ 7.9
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 728.4**	$ 682.7	$ 641.4	$ 380.5	$ 353.0
Total Assets	**$ 759.6**	$ 725.2	$ 733.2	$ 474.6	$ 483.4
Capitalization:					
Common Stock Equity	**$ 189.0**	$ 193.1	$ 139.5	$ 100.4	$ 97.8
Preferred Stock	**2.0**	2.0	2.0	2.1	2.1
Long-Term Debt, less current portion	**288.3**	248.9	249.3	159.6	140.0
Total Capitalization	**$ 479.3**	$ 444.0	$ 390.8	$ 262.1	$ 239.9
Current Portion of Long-Term Debt	**$ 0.5**	$ 0.4	$ 0.4	$ 0.4	$ 0.3
Short-term Debt	**$ 66.8**	$ 64.5	$ 74.1	$ 18.8	$ 26.0
Capital Structure Ratios:					
Common Stock Equity	**39%**	43%	36%	38%	41%
Preferred Stock	**1%**	1%	1%	1%	1%
Long-Term Debt	**60%**	56%	63%	61%	58%
Earnings Per Share Data:					
Earnings Per Average Share	**$ 0.88**	$ 1.03	$ 1.65	$ 1.52	$ 1.41
Common Stock Data:					
Shares of Common Stock—(Diluted Average Outstanding, 000's)	**10,824**	9,647	5,830	5,672	5,612
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.35**	$ 17.83	$ 17.90	$ 17.50	$ 17.30
Electric and Gas Sales:					
Electric Distribution Sales (Millions kWh)	**1,691.1**	1,618.8	1,695.9	1,743.0	1,751.5
Firm Natural Gas Distribution Sales (Millions Therms)	**172.9**	178.7	47.2	28.4	26.4

[1] As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in all reporting periods.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

OVERVIEW

Unitil is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company from NiSource.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy, which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,900 electric customers and 70,800 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite State, a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to North American pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and Unitil had an investment in Net Utility Plant of $476.5 million at December 31, 2010. Unitil's total revenue was $358.4 million in 2010, which includes revenue to recover the approved cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not affected by changes in the cost of purchased electricity and natural gas. Earnings from Unitil's utility operations are derived from the return on investment in the three distribution utilities and Granite State.

Unitil also conducts non-regulated operations principally through Usource, which is wholly-owned by Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Usource's total revenues were $4.6 million in 2010. The Company's other subsidiaries include Unitil Service, which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, and Unitil Realty, which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- the Company's regulatory environment (including regulations relating to climate change, greenhouse gas emissions and other environmental matters), which could impact the rates the Company is able to charge, the Company's authorized rate of return and the Company's ability to recover costs in its rates;
- fluctuations in the supply of, demand for, transmission capacity and the prices of energy commodities and the Company's ability to recover energy commodity costs in its rates;
- customers' preferences on energy sources;
- severe storms and the Company's ability to recover storm costs in its rates;
- the Company's stranded electric generation and generation-related supply costs and the Company's ability to recover stranded costs in its rates;
- declines in the valuation of capital markets, which could require the Company to make substantial cash contributions to cover its pension obligations, and the Company's ability to recover pension obligation costs in its rates;
- general economic conditions, which could adversely affect (i) the Company's customers and, consequently, the demand for the Company's distribution services, (ii) the availability of credit and liquidity resources and (iii) certain of the Company's counterparty's obligations (including those of its insurers and lenders);
- the Company's ability to obtain debt or equity financing on acceptable terms;
- increases in interest rates, which could increase the Company's interest expense;
- restrictive covenants contained in the terms of the Company's and its subsidiaries' indebtedness, which restrict certain aspects of the Company's business operations;
- variations in weather, which could decrease demand for the Company's distribution services;
- long-term global climate change, which could adversely affect customer demand or cause extreme weather events that could disrupt the Company's electric and natural gas distribution services;
- numerous hazards and operating risks relating to the Company's electric and natural gas distribution activities, which could result in accidents and other operating risks and costs;
- catastrophic events;
- the Company's ability to retain its existing customers and attract new customers;
- the Company's energy brokering customers' performance under multi-year energy brokering contracts; and
- increased competition.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A Risk Factors.

RESULTS OF OPERATIONS

The following discussion of the Company's financial condition and results of operations should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report.

Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the financing associated with the Acquisitions. As a result of the Acquisitions and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisitions and stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher (due to heating-related requirements), and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Net Income and EPS Overview

2010 Compared to 2009—The Company's Earnings Applicable to Common Shareholders (Earnings) were $9.5 million, or $0.88 per share, for the full year of 2010. This compares to Earnings of $9.9 million, or $1.03 per share in 2009.

The Company's Earnings were $5.2 million, or $0.48 per share, for the fourth quarter of 2010, compared to Earnings of $1.2 million, or $0.11 per share in the fourth quarter of 2009. The results for 2009 include a non-recurring accounting charge in the fourth quarter for a regulatory order in Massachusetts requiring the refund $4.9 million of natural gas supply costs. The Company has appealed this order to the Massachusetts Supreme Judicial Court and anticipates a ruling in late 2011.

Electric sales margin increased $4.8 million in 2010 compared to 2009. The increase in electric sales margin reflects higher electric kilowatt-hour (kWh) sales and an electric rate increase implemented in July 2010 for Unitil Energy, the Company's New Hampshire electric operating utility. The increase in electric sales reflects higher than average summer temperatures in the Company's utility service territories in 2010 coupled with an improving regional economy. According to ISO-New England, the electric transmission grid operator for the New England region, July of 2010 was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month. On a weather-normalized basis, kWh sales in 2010 increased approximately 1.6% compared to 2009.

Natural gas sales margin increased $2.3 million in 2010 compared to 2009, reflecting the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above. Absent the effect of this refund, natural gas sales margin decreased $2.6 million in 2010 compared to 2009, principally due to the milder winter heating season in the early part of 2010 compared to 2009. Heating Degree Days in 2010 were 9% fewer than in the prior year. On a weather-normalized basis, natural gas therm sales for the full year of 2010 were essentially flat with therm sales in 2009.

Total Operation & Maintenance (O&M) expenses increased $4.1 million in 2010 compared to 2009. The changes in O&M expenses reflect higher utility operating costs. O&M expenses in 2010 also reflect the full integration of Northern Utilities and Granite State into the Company's consolidated operating results. In 2009, the Company recognized professional fees of approximately $3.0 million related to regulatory and legal matters concerning the Company's preparation and response to the severe ice storm that struck the New England region in December 2008.

Depreciation and Amortization expense increased $1.5 million in 2010 compared to 2009, reflecting higher depreciation on normal utility plant additions partially offset by lower amortization expense in the current year.

Interest Expense, net increased $2.3 million in 2010 compared to 2009. The increase is primarily due to the issuance of $40 million of long-term notes by Unitil Energy and Northern Utilities in March 2010.

Federal and State Income Taxes decreased by $0.9 million in 2010 due to lower pre-tax income in 2010 compared to 2009.

All other expenses increased $0.8 million in 2010 compared to 2009, primarily reflecting higher property taxes and payroll taxes.

Usource, our non-regulated energy brokering business, recorded revenues of $4.6 million in 2010, an increase of $0.3 million compared to 2009.

In 2010, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2011 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

2009 Compared to 2008—The Company's Earnings Applicable to Common Shareholders was $9.9 million for 2009, compared to $9.6 million for 2008. Earnings per common share were $1.03 for 2009, ($0.62) per share lower than earnings of $1.65 in 2008. The lower earnings per common share primarily reflect higher regulatory and legal expenses in 2009 associated with the severe ice storm that struck New England in December 2008 and other significant non-recurring regulatory matters.

A more detailed discussion of the Company's 2010 and 2009 results of operations and a year-to-year comparison of changes in financial position are presented below.

Gas Sales, Revenues and Margin

Therm Sales—Unitil's total therm sales of natural gas decreased 3.2% in 2010 compared to 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of milder winter temperatures in the early part of 2010 compared to 2009. Heating Degree Days in 2010 were 9% fewer than in the prior year. On a weather-normalized basis, natural gas therm sales in 2010 were essentially flat compared to 2009.

Unitil's total therm sales of natural gas increased 278.6% in 2009 compared to 2008, reflecting the contribution to sales by Northern Utilities. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas decreased 0.7% in 2009 compared to 2008, reflecting a decrease of 2.0% in sales to residential customers and flat year over year sales to C&I customers. The decrease in sales to residential customers reflects lower average usage by our customers, due to a slowing economy and energy conservation, partially offset by a colder winter heating season in the first quarter of 2009.

The following table details total therm sales for the last three years, by major customer class:

Therm Sales (millions)				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	Therms	%	Therms	%
Residential	**35.1**	36.7	13.3	(1.6)	(4.4%)	23.4	175.9%
Commercial / Industrial	**137.8**	142.0	33.9	(4.2)	(3.0%)	108.1	318.9%
Total	**172.9**	178.7	47.2	(5.8)	(3.2%)	131.5	278.6%

Gas Operating Revenues and Sales Margin—The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenues and Sales Margin (millions)

				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$	%(1)	$	%(1)
Gas Operating Revenue:							
Residential	**$ 61.5**	$ 62.0	$27.5	$(0.5)	(0.3%)	$34.5	60.6%
Commercial / Industrial	**88.6**	90.8	29.4	(2.2)	(1.4%)	61.4	107.9%
Total Gas Operating Revenue	**$150.1**	$152.8	$56.9	$(2.7)	(1.7%)	$95.9	168.5%
Cost of Gas Sales:							
Purchased Gas	**$ 90.5**	$ 96.4	$37.3	$(5.9)	(3.8%)	$59.1	103.9%
Conservation & Load Management	**2.8**	1.9	0.2	0.9	0.6%	1.7	2.9%
Total Cost of Gas Sales	**$ 93.3**	$ 98.3	$37.5	$(5.0)	(3.2%)	$60.8	106.8%
Gas Sales Margin	**$ 56.8**	$ 54.5	$19.4	$ 2.3	1.5%	$35.1	61.7%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues decreased $2.7 million, or 1.7%, in 2010 compared to 2009. Total Gas Operating Revenues include the recovery of the approved cost of sales, which are recorded as Purchased Gas and Conservation and Load Management (C&LM) in Operating Expenses. The decrease in Total Gas Operating Revenues in 2010 reflects lower Purchased Gas costs of $5.9 million partially offset by higher C&LM revenues of $0.9 million and higher sales margin of $2.3 million.

Purchased Gas and C&LM revenues decreased $5.0 million, or 3.2%, of Total Gas Operating Revenues in 2010 compared to 2009, primarily reflecting the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above, and lower sales of natural gas. Purchased Gas revenues include the recovery of the approved cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $2.3 million in 2010 compared to 2009, reflecting the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above. Absent the effect of this refund, natural gas sales margin decreased $2.6 million in 2010 compared to 2009, principally due to lower sales of natural gas, which reflect the effect of the milder winter heating season in the early part of 2010 compared to 2009.

Total Gas Operating Revenues increased $95.9 million, or 168.5%, in 2009 compared to 2008, reflecting the inclusion of Northern Utilities and Granite State for the full year in 2009. Total Gas Operating Revenues include the recovery of the approved cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The increase in Total Gas Operating Revenues in 2009 reflects higher Purchased Gas costs of $59.1 million, higher C&LM revenues of $1.7 million and higher sales margin of $35.1 million.

Natural gas sales margin increased $35.1 million in 2009 compared to 2008, reflecting the contribution to natural gas sales by Northern Utilities and Granite State. Natural gas sales margin also includes the unfavorable effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales—Unitil's total electric kWh sales increased 4.5% in 2010 compared to 2009. Electric kWh sales to residential customers and C&I customers increased 5.5% and 3.8%, respectively, in 2010 compared to 2009. The increased sales reflect higher than average summer temperatures in the Company's utility service territories in 2010 where there were approximately 61% more Cooling Degree

Days in the three month period ended September 30, 2010, compared to the prior year, coupled with an improving regional economy. According to ISO-New England, the grid operator for the New England region, July of 2010 was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month. On a weather-normalized basis, kWh sales in 2010 increased 1.6% compared to 2009.

Unitil's total electric kWh sales decreased 4.5% in 2009 compared to 2008. Electric kWh sales to residential customers and C&I customers decreased 2.2% and 6.1%, respectively, in 2009 compared to 2008. The lower electric kWh sales in 2009 compared to 2008 reflect lower average usage by our customers due to the continued regional economic slowdown and milder summer weather in 2009. Average summer temperatures in the Company's electric service territories, as measured by cooling degree days, were 31% cooler in 2009 compared to the same period in 2008 and were 26% cooler than normal.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (millions)				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	kWh	%	kWh	%
Residential	**681.2**	645.9	660.2	35.3	5.5%	(14.3)	(2.2%)
Commercial / Industrial	**1,009.9**	972.9	1,035.7	37.0	3.8%	(62.8)	(6.1%)
Total	**1,691.1**	1,618.8	1,695.9	72.3	4.5%	(77.1)	(4.5%)

Electric Operating Revenues and Sales Margin—The following table details Total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenues (millions)				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$	%(1)	$	%(1)
Electric Operating Revenue:							
Residential	**$108.5**	$108.9	$114.5	$ (0.4)	(0.2%)	$ (5.6)	(2.5%)
Commercial / Industrial	**95.2**	101.0	113.0	(5.8)	(2.7%)	(12.0)	(5.2%)
Total Electric Operating Revenue	**$203.7**	$209.9	$227.5	$ (6.2)	(2.9%)	$(17.6)	(7.7%)
Cost of Electric Sales:							
Purchased Electricity	**$137.7**	$151.6	$170.1	$(13.9)	(6.6%)	$(18.5)	(8.1%)
Conservation & Load Management	**6.0**	3.1	2.6	2.9	1.4%	0.5	0.2%
Total Cost of Electric Sales	**$143.7**	$154.7	$172.7	$(11.0)	(5.2%)	$(18.0)	(7.9%)
Electric Sales Margin	**$ 60.0**	$ 55.2	$ 54.8	$ 4.8	2.3%	$ 0.4	0.2%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues decreased by $6.2 million, or 2.9%, in 2010 compared to 2009. Total Electric Operating Revenues include the recovery of approved costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The net decrease in Total Electric Operating Revenues in 2010 reflects lower Purchased Electricity costs of $13.9 million offset by higher C&LM revenues of $2.9 million and higher sales margin of $4.8 million.

Purchased Electricity and C&LM revenues decreased $11.0 million, or 5.2%, of Total Electric Operating Revenues in 2010 compared to 2009, reflecting an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity costs, partially offset by higher spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the approved cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $4.8 million in 2010 compared to 2009. The increase in electric sales margin reflects higher electric kWh sales and an electric rate increase, implemented in July 2010 for the Company's New Hampshire electric distribution utility.

Total Electric Operating Revenues decreased by $17.6 million, or 7.7%, in 2009 compared to 2008. Total Electric Operating Revenues include the recovery of approved costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The net decrease in Total Electric Operating Revenues in 2009 reflects lower Purchased Electricity costs of $18.5 million offset by higher C&LM revenues of $0.5 million and higher sales margin of $0.4 million.

Electric sales margin increased $0.4 million in 2009 compared to 2008. The increase in electric sales margin reflects higher rates offset by lower sales volumes. Total electric sales decreased 4.5% in 2009 compared to 2008, reflecting lower average usage by our customers due to the continued economic slowdown and milder summer weather in 2009.

Operating Revenue—Other

Total Other Revenue increased $0.3 million in 2010 compared to 2009 and $0.5 million in 2009 compared to 2008. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (millions)

				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	**2009**	**2008**	**$**	**%**	**$**	**%**
Usource	**$4.6**	$4.3	$3.8	$0.3	7.0%	$0.5	13.2%
Total Other Revenue	**$4.6**	$4.3	$3.8	$0.3	7.0%	$0.5	13.2%

Operating Expenses

Purchased Gas—Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $5.9 million, or 6.1%, in 2010 compared to 2009. This increase reflects the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above. Absent the effect of this refund, Purchased Gas decreased $1.0 million in 2010 compared to 2009, principally due to lower sales of natural gas, which reflect the effect of the milder winter heating season in the early part of 2010 compared to 2009, partially offset by higher natural gas commodity prices in 2010. The Company recovers the approved costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in approved expenses do not affect earnings.

In 2009, Purchased Gas increased $59.1 million, or 158.4%, compared to 2008. This increase primarily reflects the inclusion of Northern Utilities for the full year in 2009.

Purchased Electricity—Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity decreased $13.9 million, or 9.2%, in 2010 compared to 2009. This decrease reflects an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity costs, partially offset by increased sales. The Company recovers the approved costs of Purchased Electricity in its rates at cost and therefore changes in approved expenses do not affect earnings.

In 2009, Purchased Electricity expenses decreased $18.5 million, or 10.9%, compared to 2008, reflecting lower sales volumes and lower electric commodity prices.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. Total O&M expenses increased $4.1 million, or 9.2%, in 2010 compared to 2009. The changes in O&M expenses reflect higher compensation and retiree employee benefit expenses of $2.7 million and higher utility operating costs of $1.4 million. Utility operating costs primarily consist of utility distribution and transmission system maintenance costs, bad debt expenses, office expenses and insurance costs. O&M expenses in 2010 reflect the full integration of Northern Utilities and Granite State into the Company's consolidated operating results.

In 2009, total O&M expense increased $17.2 million, or 62.5%, compared to 2008. The inclusion of Northern Utilities and Granite State for the full year in 2009 accounted for $8.8 million of the increase. In addition, higher compensation and retiree and employee benefit expenses of $2.2 million and net other utility operating costs of $0.4 million contributed to the increase in O&M expenses year over year. In 2009 the Company expensed professional fees of approximately $3.0 million related to regulatory and legal matters concerning the December 2008 ice storm. The increase in O&M expenses in 2009 over 2008 also reflects lower O&M recorded in 2008 due to the receipt of a $2.8 million insurance settlement in that year.

Conservation & Load Management—C&LM expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 65% of these costs are related to electric operations and 35% to gas operations.

Total Conservation & Load Management expenses increased by $3.8 million, in 2010 compared to 2009. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total Conservation & Load Management expenses increased by $2.2 million in 2009 compared to 2008.

Depreciation and Amortization—Depreciation and Amortization expense increased $1.5 million, or 5.5% in 2010 compared to 2009. This increase reflects higher depreciation on normal utility plant additions partially offset by lower amortization expense in the current year.

In 2009, Depreciation and Amortization expense increased $8.3 million, or 43.5%, compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009 and higher depreciation on normal utility plant additions.

Local Property and Other Taxes—Local Property and Other Taxes increased $0.8 million, or 7.7%, in 2010 compared to 2009. This increase reflects higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

In 2009, Local Property and Other Taxes increased by $4.1 million, or 65.1%, compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009, and higher local property tax rates on higher levels of utility plant in service.

Federal and State Income Taxes—Federal and State Income Taxes decreased by $0.9 million in 2010 compared to 2009 due to lower pre-tax operating income in 2010 compared to 2009 (See Note 8 to the accompanying Consolidated Financial Statements).

Federal and State Income Taxes increased by $0.8 million in 2009 compared to 2008 due to higher pre-tax operating income in 2009 compared to 2008 (See Note 8 to the accompanying Consolidated Financial Statements).

Other Non-operating Expenses (Income)—Other Non-operating Expenses (Income) was flat in 2010 compared to 2009 and in 2009 compared to 2008.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated (See Note 4 to the accompanying Consolidated Financial Statements).

Interest Expense, net increased $2.3 million in 2010 compared to 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in 2010.

In 2009, Total Interest Expense, net increased by $5.3 million compared to 2008. The increase was primarily due to the issuance of $90 million of long-term notes issued by Northern Utilities and Granite State in December 2008 to partially finance the acquisition and higher average borrowings during 2009, partially offset by increases in interest income on regulatory assets and Allowance for Funds Used During Construction (AFUDC) in 2009.

LIQUIDITY, COMMITMENTS AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

On March 2, 2010, both Unitil Energy and Northern Utilities closed long-term financings:

(i) Unitil Energy closed $15,000,000 of First Mortgage Bonds, through a private placement to institutional investors. The First Mortgage Bonds have a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

(ii) Northern Utilities closed $25,000,000 of Senior Unsecured Notes, through a private placement to institutional investors. The Senior Unsecured Notes have a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

The Company, along with its subsidiaries, are individually and collectively members of the Unitil Cash Pool (the Cash Pool). The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool allows for an efficient exchange of cash among the Company and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on actual interest costs from lenders under the Company's revolving credit facility. At December 31, 2010 and 2009, all of the Company's subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

Unitil has a revolving credit facility with a group of banks that extends to October 8, 2013. The borrowing limit under the revolving credit facility is $80.0 million. There was $66.8 million and $64.5 million in short-term debt outstanding through bank borrowings under the revolving credit facility at December 31, 2010 and 2009, respectively. The total amount of credit available under the Company's revolving credit facility was $13.2 million and $15.5 million at December 31, 2010 and 2009, respectively. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter. As of December 31, 2010 and 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

The continued availability of various methods of financing, as well as the choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of earnings, cash flows, financial position; and the competitive pricing offered by financing sources.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2010.

		Payments Due by Period			
Significant Contractual Obligations (millions) as of December 31, 2010	**Total**	**2011**	**2012-2013**	**2014-2015**	**2016 & Beyond**
Long-term Debt	$288.8	$ 0.5	$ 1.0	$ 6.5	$280.8
Interest on Long-term Debt	284.1	20.0	39.9	39.6	184.6
Gas Supply Contracts	276.0	43.5	74.0	68.0	90.5
Power Supply Contract Obligations	21.8	9.1	9.6	1.4	1.7
Other	5.6	2.0	2.4	0.9	0.3
Total Contractual Cash Obligations	$876.3	$75.1	$126.9	$116.4	$557.9

The Company and its subsidiaries have material energy supply commitments that are discussed in Note 6 to the accompanying Consolidated Financial Statements. Cash outlays for the purchase of electricity and natural gas to serve customers are subject to reconciling recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over-collected cash over subsequent periods of less than a year.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2010, there were approximately $36.3 million of guarantees outstanding and the longest term guarantee extends through December 31, 2012. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed below.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $11.7 million and $10.0 million outstanding at December 31, 2010 and 2009, respectively, related to these asset management agreements. The amount of natural gas inventory released in December 2010, which is payable in January 2011, is $3.9 million and recorded in Accounts Payable at December 31, 2010.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $3.8 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million.

Benefit Plan Funding

The Company, along with its subsidiaries, made cash contributions to its Pension Plan in the amount of $4.3 million and $4.2 million in 2010 and 2009, respectively. The Company, along with its subsidiaries, contributed $3.5 million and $2.8 million to Voluntary Employee Benefit Trusts (VEBT) in 2010 and 2009, respectively. The Company, along with its subsidiaries, expects to continue to make contributions to its

Pension Plan and the VEBT's in 2011 and future years at minimum required and discretionary funding levels consistent with the amounts recovered in the distribution utilities' rates for these other postretirement benefit costs. (See Note 10 to the accompanying Consolidated Financial Statements.)

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements. (See Note 4 to the accompanying Consolidated Financial Statements.)

Cash Flows

Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash for 2010 and 2009.

(millions)	2010	2009
Cash Provided by Operating Activities	**$25.9**	$50.9

Cash Provided by Operating Activities—Cash Provided by Operating Activities was $25.9 million in 2010, a decrease of ($25.0) million over the comparable period in 2009. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes, was $49.0 million in 2010 compared to $44.5 million in 2009, representing an increase of $4.5 million. Working capital changes in Current Assets and Liabilities resulted in a ($12.1) million net use of cash in 2010, compared to a $29.4 million net source of cash in 2009, representing a net increased use of cash of ($41.5) million primarily due to increased uses of cash in Accounts Receivable ($9.6) million, Accrued Revenue ($15.6) million, Refundable Taxes ($7.3) million, and Gas Inventory ($13.6 million). Deferred Regulatory and Other Charges resulted in a ($7.9) million use of cash in 2010, compared to a ($24.6) million use of cash in 2009. In 2010, Deferred Regulatory and Other Charges include an approximately ($7.4) million use of cash related to the funding of non-recurring deferred regulated charges related to the 2010 wind storm. In 2009, Deferred Regulatory and Other Charges include an approximately ($14.0) million use of cash related to the funding of non-recurring deferred regulated charges related to the 2008 Ice Storm. All Other, net operating activities resulted in a use of cash of ($3.1) million in 2010 compared to a source of cash of $1.6 million in 2009.

(millions)	2010	2009
Cash (Used in) Investing Activities	**$(49.6)**	$(65.6)

Cash (Used in) Investing Activities—Cash Used in Investing Activities was ($49.6) million for 2010 compared to ($65.6) million in 2009. Capital expenditures for property, plant and equipment additions were ($49.6) million in 2010 compared to ($58.7) million in 2009, representing a decreased use of cash of $9.1 million. Cash Used in Investing Activities in 2009 included ($6.9) million related to the Company's acquisition of Northern Utilities and Granite State. Capital expenditures are projected to be approximately ($57) million in 2011, primarily reflecting normal electric and gas utility system additions.

(millions)	2010	2009
Cash Provided by Financing Activities	**$24.9**	$10.9

Cash Provided by Financing Activities—Cash Provided by Financing Activities was $24.9 million in 2010 compared to $10.9 million in 2009. In 2010, sources of cash from financing activities included proceeds from issuance of long-term debt, net of $39.5 million, discussed above, proceeds from issuance of short-term debt of $2.3 million and the issuance of common stock of $0.9 million. Uses of cash included regular quarterly dividend payments on common and preferred stock of ($15.0) million, a decrease in gas inventory financing of ($2.2) million and all other financing activities which resulted in a use of ($0.6) million.

FINANCIAL COVENANTS AND RESTRICTIONS

The agreements under which the Company's and its subsidiaries' long-term debt were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations and covenants restricting the ability to (i) pay dividends, (ii) incur indebtedness and liens, (iii) merge or consolidate with another entity or (iv) sell, lease or otherwise dispose of all or substantially all assets. (See Note 4 to the accompanying Consolidated Financial Statements.)

The long-term debt and preferred stock of Unitil, Unitil Energy, Fitchburg, Northern Utilities, Granite State and Unitil Realty are privately held, and the Company does not issue commercial paper. For these reasons, the debt securities of Unitil and its subsidiaries are not publicly rated.

The Company's revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter.

The Company and its subsidiaries are currently in compliance with all such covenants in these debt instruments.

DIVIDENDS

Unitil's annualized common dividend was $1.38 per common share in 2010, 2009 and 2008. Unitil's dividend policy is reviewed periodically by the Board of Directors. Unitil has maintained an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2011 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

LEGAL PROCEEDINGS

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2011. The Company continues to believe the suit is without merit and will defend itself vigorously.

REGULATORY MATTERS

Overview (Unitil Energy, Fitchburg, and Northern Utilities)—Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territories at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern

Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next one to four years, is $46.8 million as of December 31, 2010 including $13.3 million recorded in Current Assets as Accrued Revenue on the Company’s Consolidated Balance Sheet. Unitil’s distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Fitchburg—Base Rate Case Filings—On January 14, 2011, Fitchburg filed a petition with the MDPU requesting approval of a comprehensive revenue decoupling proposals and for an increase in its electric and gas distribution rates. The Company’s revenue decoupling proposal is modeled closely on proposals already approved by the Department for other gas and electric utilities operating in the Commonwealth of Massachusetts and is intended to facilitate the achievement of important public policy objectives of fostering energy efficiency, conservation and protecting the environment. The proposed rates are scheduled to change in conjunction with the implementation of revenue decoupling and are subject to the review and approval of the MDPU.

In its rate filing the Company made a request for an increase of $7.1 million in its electric distribution rates, including the recovery of deferred emergency storm restoration costs. The Company also proposed a rate-impact mitigation alternative offset, in whole, the electric distribution rate increase with a corresponding decrease in its Transition Charge. The Transition Charge is the means by which Fitchburg recovers its power supply-related stranded costs and other restructuring-related regulatory assets, discussed above. Any offsetting decrease in the Transition Charge would allow for the recovery of the restructuring related stranded costs over an extended term. The Company’s filing included a request for an increase of $4.4 million in its gas distribution rates. The MDPU issued an order suspending and deferring the use of the rates until August 2, 2011, pending an investigation and analysis of the Company’s filing.

Granite State Gas Transmission, Inc.—Base Rate Case Filing—On June 29, 2010, Granite State filed a base transportation rate increase of $2.3 million in annual revenue with the FERC, which is Granite State’s first request for a rate change since its last general rate case in 1997. On July 30, 2010, the FERC ordered the rate increase to be effective on January 1, 2011, subject to refund and hearing and settlement procedures. On November 30, 2010, a settlement was filed on behalf of Granite State and all intervenors in the proceeding, resolving all issues in the docket. The settlement provides for an increase of approximately $1.7 million in annual revenue, based on new gas transportation rates to be effective January 1, 2011. The settlement was approved by the FERC on January 31, 2011.

Unitil Energy Rate Case Filing—On April 15, 2010, Unitil Energy filed a proposed base rate increase of $10.1 million, an increase of 6.5 percent above present rates. In addition, Unitil Energy’s filing also included a proposed long-term rate plan establishing future rate step adjustments for utility plant investments and enhanced reliability and vegetation management program expenditures. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy of $5.2 million (annual) effective July 1, 2010 which is being collected by a uniform per kilowatt-hour (kWh) surcharge of $0.00438 on each of Unitil Energy’s current rate schedules. Once permanent rates are approved by the NHPUC, they

will be reconciled to the date temporary rates were ordered, July 1, 2010. The Company is currently engaged in settlement proceedings regarding the permanent rate level and a long-term rate plan. A hearing in this matter is scheduled for early February 2011.

Major Wind Storm—On February 25, 2010, a significant wind storm struck portions of the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including approximately 85% of the Unitil Energy's customers. The Company spent approximately $7.4 million for the repair and replacement of electric distribution systems damaged during the storm, including $1.5 million related to capital construction and $5.9 million which has been deferred as a regulatory asset. Unitil Energy, in its base rate case filing discussed above, has requested recovery in rates for the costs associated with the emergency repair of its electric distribution system for damage caused by this storm.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region. The Company spent approximately $24.0 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.6 million related to capital construction and $15.4 million which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. If the Company is unable to recover a significant amount of these deferred storm costs, or if the Company's recovery of these costs is significantly delayed, then the Company's financial condition or results of operations could be adversely affected.

On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. On September 24, 2010, the NHPUC issued its final order in this matter and closed its investigation, accepting the NHPUC Staff's report finding that Unitil Energy had acted reasonably.

On November 9, 2009, the NHPUC granted Unitil Energy's petition to defer and record as a regulatory asset costs associated with electric distribution system damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's pending base rate case. The order clarified that the issues of the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are to be reviewed in the rate case. As of December 31, 2010, Unitil Energy has deferred approximately $2.2 million associated with the repair of its electric distribution system for future recovery in rates.

On December 30, 2009, the MDPU approved Fitchburg's petition to defer and record as a regulatory asset costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. The order of approval made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and confirmed that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. As of December 31, 2010, Fitchburg has deferred approximately $13.2 million associated with the repair of its electric distribution system for future recovery in rates.

The MDPU conducted an investigation of Fitchburg's preparation for, and response to, the December 2008 Ice Storm during the first half of 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service, and ordered several remedial actions. First, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices. The management audit, which is being performed by Jacobs Consultancy, Inc., began in the fourth quarter of 2010. Second, the MDPU directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. All of these operational and capital improvements have either been completed or are being implemented, and remain subject to MDPU review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

Fitchburg—Electric Operations—On November 24, 2010, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery continues through a Transition Charge Surcharge of $0.00400 per kWh. Changes to the Pension/ PBOP Adjustment, Residential Assistance Adjustment Factor, and Net Metering Recovery Surcharge were proposed in other proceedings. The rates were approved effective January 1, 2011, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2009 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting regulations concerning the items required by House Bill 4329. On July 30, 2010, the MDPU approved Fitchburg's electric and gas Emergency Response Plans.

Fitchburg—Gas Operations—On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement order to the Massachusetts Supreme Judicial Court (SJC). Fitchburg believes that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. The Company filed its Initial brief in this matter on January 10, 2011. This appeal remains pending before the Massachusetts SJC.

Fitchburg—Other—On February 11, 2009, the Massachusetts SJC issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The Massachusetts SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Massachusetts SJC, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, special tariffs to allow the net metering of customer-owned renewable generation, and terms and conditions for purchasing supplier receivables. Three year energy efficiency investment plans, plans to establish smart grid pilot programs, and net metering tariffs have been approved by the MDPU. Proposals to purchase long-term contracts for renewable energy and terms and conditions for purchasing supplier receivables are under review in a separately designated docket.

On March 1, 2010, Fitchburg submitted its annual filing to the MDPU of the 2009 Service Quality Reports for both its gas and electric divisions. On October 20, 2010, the MDPU issued its order with respect to Fitchburg's gas division's Report and noted that Fitchburg met or exceeded its established benchmarks in all Service Quality measures, that Fitchburg's performance was consistent with the MDPU's Service

Quality Guidelines and Fitchburg's Service Quality plan. An order on Fitchburg's electric division's Service Quality plan has not yet been issued and the matter remains pending.

Unitil Energy—Other—In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources (DER). An order approving a settlement agreement for a time-of-use pilot program was issued on February 26, 2010. On June 11, 2010, the NHPUC issued an order on the remaining two proposed projects and cost recovery. The NHPUC denied one of the two projects, citing that the costs outweighed the benefits but found the other project to be in the public interest. On November 1, 2010 Unitil Energy filed adjustments to base distribution rates to collect actual costs associated with authorized DER projects. This matter remains pending.

On June 17, 2010, Unitil Energy made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2010, including reconciliation of prior year costs and revenues. On July 30, 2010, the NHPUC approved the rate filing and reconciliation.

Northern Utilities—On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation (NOPVs) of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's consolidated balance sheet at December 31, 2010 was $0.7 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in portions of Northern Utilities' Maine service areas. In an order issued on July 30, 2010, the MPUC approved a Settlement Agreement resolving this matter, filed on behalf of Northern Utilities, the Maine Office of the Public Advocate, and several state legislator intervenors, which was filed with the MPUC on July 6, 2010. Under the Agreement, Northern Utilities will proceed with a comprehensive upgrade and replacement program (the Program), which will provide for the systematic replacement of cast iron, wrought iron and bare steel pipe in Northern Utilities' natural gas distribution system in Portland and Westbrook, Maine and the conversion of the system to intermediate pressure. The Agreement establishes the objective of completing the Program by the end of the 2024 construction season. Under the Agreement, the parties agreed to support a cost recovery mechanism that will provide for the timely recovery of prudently-incurred costs of the Program. The features of this cost recovery mechanism will be finalized during Northern Utilities' next base rate case proceeding, which is anticipated to be filed in early 2011.

ENVIRONMENTAL MATTERS

Unitil's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed. Also, see Note 6 to the accompanying consolidated financial statements.

Fitchburg recovers the environmental response costs incurred at this former MGP site in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. In January 2011, Fitchburg settled with the remaining insurance carriers for approximately $2.0 million and expects to receive these payments in the first quarter of 2011. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are shared equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Also, see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES AND EMPLOYEE RELATIONS

As of December 31, 2010, the Company and its subsidiaries had 437 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2010, 150 of the Company's employees were represented by labor unions. These employees are covered by four separate collective bargaining agreements which expire on March 31, 2012, May 31, 2012, May 31, 2013 and June 5, 2014. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to negotiate new agreements prior to their expiration dates.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the Financial Accounting Standards Board Accounting Standards Codification (FASB Codification). In accordance with the FASB Codification, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The FASB Codification specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets." If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities."

The Company's principal regulatory assets and liabilities are included on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided in Note 1 thereto. The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements.

The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The FASB Codification requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's RBO and reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2010 and 2009, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000 and $300,000, respectively, in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2010 and 2009, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $728,000 and $735,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $565,000 and $576,000, respectively. (See Note 10 to the accompanying Consolidated Financial Statements).

Income Taxes—The Company is subject to Federal and State income taxes as well as various other business taxes. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes.

Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining the current and deferred tax assets and liabilities. The Company's current and deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. Periodically, the Company assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Depreciation—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2010, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements" in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 8, "Income Taxes," Note 5, "Energy Supply," Note 10, "Retirement Benefit Plans," and Note 6, "Commitment and Contingencies," to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please also refer to Item 1A. "Risk Factors".

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 2.3%, 3.4%, and 3.8% during 2010, 2009, and 2008, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Unitil Corporation and subsidiaries:

We have audited the accompanying consolidated balance sheet of Unitil Corporation and subsidiaries (the Company) as of December 31, 2010, and the related consolidated statements of earnings, cash flows and changes in common stock equity for the year then ended. We also have audited Unitil Corporation and subsidiaries' internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that *(a)* pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; *(b)* provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and *(c)* provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Unitil Corporation and subsidiaries as of December 31, 2010, and the consolidated results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Unitil Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ McGladrey & Pullen, LLP
Boston, Massachusetts
February 3, 2011

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Unitil Corporation and subsidiaries:

We have audited the accompanying consolidated balance sheet of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the years ended December 31, 2009 and 2008. The Company's management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unitil Corporation and subsidiaries as of December 31, 2009, and the consolidated results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

/s/ Caturano and Company, Inc.
Boston, Massachusetts
February 10, 2010

[THIS PAGE INTENTIONALLY LEFT BLANK]

CONSOLIDATED STATEMENTS OF EARNINGS

(Millions, except common shares and per share data)

Year Ended December 31,	2010	2009	2008
Operating Revenues:			
Gas	**$ 150.1**	$152.8	$ 56.9
Electric	**203.7**	209.9	227.5
Other	**4.6**	4.3	3.8
Total Operating Revenues	**358.4**	367.0	288.2
Operating Expenses:			
Purchased Gas	**90.5**	96.4	37.3
Purchased Electricity	**137.7**	151.6	170.1
Operation and Maintenance	**48.8**	44.7	27.5
Conservation & Load Management	**8.8**	5.0	2.8
Depreciation and Amortization	**28.9**	27.4	19.1
Provisions for Taxes:			
Local Property and Other	**11.2**	10.4	6.3
Federal and State Income	**4.5**	5.4	4.6
Total Operating Expenses	**330.4**	340.9	267.7
Operating Income	**28.0**	26.1	20.5
Other Non-Operating Expenses	**0.3**	0.3	0.3
Income Before Interest Expense	**27.7**	25.8	20.2
Interest Expense, net	**18.1**	15.8	10.5
Net Income	**9.6**	10.0	9.7
Less Dividends on Preferred Stock	**0.1**	0.1	0.1
Earnings Applicable to Common Shareholders	**$ 9.5**	$ 9.9	$ 9.6
Average Common Shares Outstanding (000's)—Basic	**10,823**	9,647	5,830
Average Common Shares Outstanding (000's)—Diluted	**10,824**	9,647	5,830
Earnings per Common Share—Basic and Diluted	**$ 0.88**	$ 1.03	$ 1.65

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS *(Millions)*

ASSETS

December 31,	2010	2009
Utility Plant:		
Electric	**$321.5**	$302.3
Gas	**360.1**	325.5
Common	**30.2**	28.9
Construction Work in Progress	**16.6**	26.0
Utility Plant	**728.4**	682.7
Less: Accumulated Depreciation	**251.9**	233.0
Net Utility Plant	**476.5**	449.7
Current Assets:		
Cash	**8.9**	7.7
Accounts Receivable, net	**36.9**	33.5
Accrued Revenue	**46.7**	44.0
Refundable Taxes	**7.5**	1.7
Gas Inventory	**10.6**	14.3
Material and Supplies	**2.9**	2.6
Prepayments and Other	**3.6**	3.0
Total Current Assets	**117.1**	106.8
Noncurrent Assets:		
Regulatory Assets	**143.0**	144.5
Other Noncurrent Assets	**23.0**	24.2
Total Noncurrent Assets	**166.0**	168.7
TOTAL ASSETS	**$759.6**	$725.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (cont.) *(Millions)*

CAPITALIZATION AND LIABILITIES

December 31,	2010	2009
Capitalization:		
Common Stock Equity	**$189.0**	$193.1
Preferred Stock	**2.0**	2.0
Long-Term Debt, Less Current Portion	**288.3**	248.9
Total Capitalization	**479.3**	444.0
Current Liabilities:		
Long-Term Debt, Current Portion	**0.5**	0.4
Accounts Payable	**26.5**	25.1
Short-Term Debt	**66.8**	64.5
Energy Supply Contract Obligations	**17.0**	23.1
Other Current Liabilities	**16.1**	16.6
Total Current Liabilities	**126.9**	129.7
Deferred Income Taxes	**43.8**	39.8
Noncurrent Liabilities:		
Energy Supply Contract Obligations	**12.6**	21.7
Retirement Benefit Obligations	**74.0**	65.5
Environmental Obligations	**14.5**	14.3
Other Noncurrent Liabilities	**8.5**	10.2
Total Noncurrent Liabilities	**109.6**	111.7
TOTAL CAPITALIZATION AND LIABILITIES	**$759.6**	$725.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS *(Millions)*

Year Ended December 31,	2010	2009	2008
Operating Activities:			
Net Income	**$ 9.6**	$ 10.0	$ 9.7
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**28.9**	27.4	19.1
Deferred Taxes Provision	**10.5**	7.1	7.4
Changes in Working Capital Items:			
Accounts Receivable	**(3.4)**	6.2	(6.4)
Accrued Revenue	**(2.7)**	12.9	(10.3)
Refundable Taxes	**(5.8)**	1.5	(2.5)
Gas Inventory	**3.7**	17.3	—
Accounts Payable	**1.4**	(3.4)	11.4
Other Changes in Working Capital Items	**(5.3)**	(5.1)	7.1
Deferred Regulatory and Other Charges	**(7.9)**	(24.6)	2.6
Other, net	**(3.1)**	1.6	9.2
Cash Provided by Operating Activities	**25.9**	50.9	47.3
Investing Activities:			
Property, Plant and Equipment Additions	**(49.6)**	(58.7)	(28.3)
Acquisitions, net (See Note 2)	**—**	(6.9)	(209.9)
Cash (Used In) Investing Activities	**(49.6)**	(65.6)	(238.2)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt, net	**2.3**	(9.6)	55.3
Proceeds from Issuance (Repayment) of Long-Term Debt, net	**39.5**	(0.4)	89.6
Net Increase (Decrease) in Gas Inventory Financing	**(2.2)**	(21.8)	24.0
Dividends Paid	**(15.0)**	(13.2)	(8.0)
Proceeds from Issuance of Common Stock	**0.9**	56.4	37.4
Other, net	**(0.6)**	(0.5)	(0.5)
Cash Provided by Financing Activities	**24.9**	10.9	197.8
Net Increase (Decrease) in Cash	**1.2**	(3.8)	6.9
Cash at Beginning of Year	**7.7**	11.5	4.6
Cash at End of Year	**$ 8.9**	$ 7.7	$ 11.5
Supplemental Information:			
Interest Paid	**$ 20.5**	$ 19.3	$ 12.5
Income Taxes Paid (Refunded)	**$ 2.3**	$ (3.8)	$ (0.5)

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2008	$ 65.3	$ 35.1	**$100.4**
Net Income for 2008		9.7	**9.7**
Dividends		(8.0)	**(8.0)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 32,754 Common Shares	0.8		**0.8**
Issuance of 2,000,000 Common Shares (See Note 3)	36.2		**36.2**
Balance at December 31, 2008	102.7	36.8	**139.5**
Net Income for 2009		10.0	**10.0**
Dividends		(13.2)	**(13.2)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 43,615 Common Shares	0.9		**0.9**
Issuance of 2,970,000 Common Shares (See Note 3)	55.5		**55.5**
Balance at December 31, 2009	159.5	33.6	**193.1**
Net Income for 2010		9.6	**9.6**
Dividends		(15.0)	**(15.0)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 41,455 Common Shares	0.9		**0.9**
Balance at December 31, 2010	$160.8	$ 28.2	**$189.0**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource). Bay State is a wholly-owned subsidiary of NiSource.

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in all reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Unitil’s principal business is the local distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the “distribution utilities”).

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy’s customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company’s corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company’s wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—The Company's consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation. The operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from December 1, 2008 through December 31, 2010.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the Massachusetts Department of Public Utilities (MDPU), Unitil Energy is regulated by the New Hampshire Public Utilities Commission (NHPUC) and Northern Utilities is regulated by the Maine Public Utilities Commission (MPUC) and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the Financial Accounting Standards Board Accounting Standards Codification (FASB Codification). The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

	December 31,	
Regulatory Assets consist of the following (millions)	2010	2009
Energy Supply Contract Obligations	**$ 21.7**	$ 34.7
Deferred Restructuring Costs	**25.0**	28.3
Subtotal—Restructuring Related Items	**46.7**	63.0
Retirement Benefit Obligations	**47.1**	43.7
Income Taxes	**12.7**	14.5
Environmental Obligations	**20.3**	22.7
Deferred Storm Charges	**21.0**	14.6
Other	**10.9**	7.9
Total Regulatory Assets	**$158.7**	$166.4
Less: Current Portion of Regulatory Assets [(1)]	**15.7**	21.9
Regulatory Assets—noncurrent	**$143.0**	$144.5

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. Under the Independent System Operator—New England (ISO-NE) Financial Assurance Policy (Policy), Unitil's affiliates Unitil Energy, Fitchburg and Unitil Power are required to provide assurance of their ability to satisfy their obligations to ISO-NE. Under this Policy, Unitil's affiliates provide cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2010 and 2009, the Unitil affiliates had deposited $7.0 million and

$4.5 million, respectively to satisfy their ISO-NE obligations. In addition, Northern Utilities has cash margin deposits to satisfy requirements for its natural gas hedging program. On December 31, 2010 and 2009, there was $1.5 million and $2.9 million, respectively, deposited for this purpose.

Goodwill and Intangible Assets—As a result of the acquisitions of Northern Utilities and Granite State, the Company recognized a bargain purchase adjustment as a reduction to Utility Plant, to be amortized over a ten year period, beginning with the date of the Acquisitions, as authorized by regulators. (See Note 2).

Off-Balance Sheet Arrangements—As of December 31, 2010, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases (See Note 4).

Derivatives—The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases natural gas futures contracts on the New York Mercantile Exchange (NYMEX) that correspond to the associated delivery month. Any gains or losses resulting from the change in the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company records gains and losses resulting from the change in fair value of the derivatives as regulatory liabilities or assets, then reclassifies these gains or losses into Purchased Gas when the gains and losses are passed through to customers in accordance with rate reconciling mechanisms.

As of December 31, 2010 and December 31, 2009, the Company had 1.3 billion and 1.9 billion cubic feet (BCF), respectively, outstanding in natural gas purchase contracts under its hedging program.

The tables below show derivatives, which are part of the regulatory approved hedging program, that are not designated as hedging instruments, under FASB ASC 815-20. As discussed above, the change in fair value related to these derivatives is recorded initially as a Regulatory Asset then reclassified to Purchased Gas in accordance with the recovery mechanism. The tables below include disclosure of the Regulatory Asset and reclassifications from the Regulatory Asset into Purchased Gas.

Fair Value Amount (millions) Offset in Regulatory Assets [(1)], as of:

		Fair Value	
Description	**Balance Sheet Location**	**December 31, 2010**	**December 31, 2009**
Natural Gas Futures Contracts	Other Current Liabilities	$0.8	$2.2
Natural Gas Futures Contracts	Other Noncurrent Liabilities	0.2	0.1
Total		$1.0	$2.3

(1) The current portion of Regulatory Assets are recorded as Accrued Revenue on the Company's Consolidated Balance Sheets.

	Twelve Months Ended December 31,	
(millions)	**2010**	**2009**
Amount of (Gain)/Loss Recognized in Regulatory Assets for Derivatives:		
Natural Gas Futures Contracts	$3.9	$5.9
Amount of Loss Reclassified into Consolidated Statements of Earnings [(2)]:		
Purchased Gas	$5.2	$9.3

(2) These amounts are offset in the Consolidated Statements of Earnings with the recognition of accrued revenue as a component of Gas Operating Revenue and therefore there is no effect on earnings.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition—Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates. (See Note 10.)

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2010, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below. (See Note 6).

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 2.25%, 3.24% and 4.58% in 2010, 2009 and 2008, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At

December 31, 2010 and 2009, the Company estimates that the negative salvage value of future retirements recorded on the consolidated balance sheet in Accumulated Depreciation is $35.5 million and $37.2 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2010 – 3.99%, 2009 – 4.02% and 2008 – 3.94%.

Gas Inventory—The weighted average cost methodology is used to value natural gas in storage.

Environmental Matters—The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has or will recover substantially all of the costs of the environmental remediation work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 6, Commitments and Contingencies. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation using the fair value-based method (See Note 3).

Sales and Consumption Taxes—The Company bills its customers sales tax in Massachusetts and Maine and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

Income Taxes—The Company is subject to Federal and State income taxes as well as various other business taxes. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes.

Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining the current and deferred tax assets and liabilities. The Company's current and deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. Periodically, the Company assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Dividends—The Company's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors. For the years ended December 31, 2010, 2009 and 2008, the Company paid a dividend at an annual rate of $1.38 per common share.

Other Recently Issued Pronouncements—There are no recently issued pronouncements that the Company has not already adopted.

Subsequent Events—The Company evaluates all events or transactions through the date of the related filing. During the period for this filing, the Company did not have any material subsequent events that impacted its consolidated financial statements.

Reclassifications—Certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation.

Note 2: Acquisitions

On December 1, 2008, the Company purchased (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource pursuant to the Stock Purchase Agreement (SPA) dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil. The aggregate purchase price for the Acquisitions was $209.2 million, comprised of $160 million in cash, plus an additional working capital adjustment of $49.2 million. The largest component of working capital was approximately $30.0 million of natural gas storage inventory.

The Company accounted for the Acquisitions under the purchase method of accounting for business combinations, in accordance with FASB Statement No. 141, "Business Combinations" ("SFAS No. 141") and the FASB Codification on business combinations. As the fair value of the net assets acquired exceeded the purchase price, the Company recognized a bargain purchase price (Plant Acquisition Adjustment or PAA) at December 1, 2008. The bargain purchase amount was recorded as a reduction of Utility Plant on the Company's Consolidated Balance Sheet and in accordance with regulatory settlements, is being amortized over ten years.

In accordance with settlement agreements between the Company, the NHPUC and the MPUC regarding the Acquisitions, the Company has agreed (i) not to seek recovery of transaction and transition costs in rates and (ii) for regulatory accounting purposes, to amortize, over a ten year period, the transaction and transition costs co-terminus with the Plant Acquisition Adjustment.

Note 3: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

The Company's common stock trades under the symbol, "UTL".

The Company had 10,890,262, and 10,836,759 of common shares outstanding at December 31, 2010 and December 31, 2009, respectively.

Unitil Corporation Common Stock Offering—On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2008 Offering). As part of this 2008 common stock offering, the underwriters exercised an over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the 2008 Offering including the over-allotment were approximately $41.9 million. On May 27, 2009, the Company issued and sold 2,400,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2009 Offering). As part of the 2009 Offering, the underwriters exercised an over-allotment option and purchased an additional 300,000 shares of the Company's common stock in June 2009. The Company's net increase to Common Equity and Cash proceeds from the 2009 Offering including the over-allotment were approximately $51.2 million. The combined total net increase to Common Equity and Cash proceeds from the 2008 Offering and 2009 Offering of $93.1 million (after payment of underwriting discount, but excluding offering expenses) were used to (i) repay all amounts outstanding under the bank credit facility that the Company used to partially finance the acquisition of Northern Utilities and Granite State which closed on December 1, 2008, and related transaction costs and expenses and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt.

Dividend Reinvestment and Stock Purchase Plan—During 2010, the Company sold 41,455 shares of its common stock, at an average price of $21.88 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans resulting in net proceeds of $0.9 million. The DRP provides participants in the plan a method for investing cash dividends on the Company's common stock and cash payments in additional shares of the Company's common stock. During 2009 and 2008, the Company raised $0.9 million and $0.8 million, respectively, of additional common equity through the issuance of 43,615 and 32,754 shares, respectively, of its common stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired—During 2010, 2009 and 2008, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. The Company accounts for its stock-based compensation plans in accordance with the provisions of the FASB Codification and recognizes compensation costs at fair value at the date of grant. Details of the plans are as follows:

Restricted Stock Plan—The Company has a Restricted Stock Plan (the Plan). Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company common stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided for in the Plan. Awards fully vest over a period of four years at a rate of 25% each year.

During the vesting period, dividends on restricted shares underlying the award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit.

Restricted shares issued for 2008 – 2010 in conjunction with the Plan are presented in the following table:

Issuance Date	Shares	Aggregate Market Value (millions)
2/6/08	15,540	$0.4
2/17/09	32,260	$0.7
2/5/10	12,520	$0.3

The compensation expense associated with the issuance of shares under the Plan is being recorded over the vesting period and was $0.5 million, $0.7 million and $0.5 million in 2010, 2009 and 2008, respectively. There were 29,521 and 33,727 non-vested shares under the Plan as of December 31, 2010 and 2009, respectively. The weighted average grant date fair value of these shares was $21.77 and $22.68, respectively. At December 31, 2010, there was approximately $0.8 million of total unrecognized compensation cost under the Plan which is expected to be recognized over approximately 2.5 years. There were 472 restricted shares forfeited under the Plan during 2010. There were no cancellations under the Plan during 2010.

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998 and was terminated by the Board of Directors on January 16, 2003. The number of shares granted under this plan, as well as the terms and conditions of each grant, were determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options that were granted under this plan vested over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of the plan, key employees were granted options to purchase the Company's common stock at no less than 100% of the market price on the date the option is granted. All options had to be exercised no later than 10 years after the date on which they were granted.

There was no compensation expense associated with this plan in 2010, 2009 and 2008. The plan has remained in effect solely for the purposes of the continued administration of any options outstanding under the plan. No further grants of options have been made under this plan since it was terminated by the Board of Directors in 2003. As of December 31, 2010, 2009 and 2008, there was no aggregate intrinsic value of the options exercisable.

	2010		2009		2008	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Beginning Options Outstanding	**63,500**	**$28.90**	97,200	$27.16	107,000	$27.13
Options Granted	**—**	**—**	—	—	—	—
Options Exercised	**—**	**—**	—	—	(3,300)	$24.51
Options Forfeited/Expired	**(30,500)**	**$32.17**	(33,700)	$23.88	(6,500)	$27.99
Ending Options Outstanding	**33,000**	**$25.88**	63,500	$28.90	97,200	$27.16
Options Vested and Exercisable-end of year	**33,000**	**$25.88**	63,500	$28.90	97,200	$27.16

The following summarizes certain data for the options outstanding at December 31, 2010:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$25.00-$29.99	33,000	$25.88	0.1 years

The remaining 33,000 options outstanding under the Plan at December 31, 2010 expired without being exercised.

Preferred Stock

Two of Unitil's distribution companies, Unitil Energy and Fitchburg, have $2.0 million of preferred stock outstanding. At December 31, 2010, Unitil Energy has $0.2 million of 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and Fitchburg has two series of Redeemable, Cumulative Preferred Stock outstanding, $0.8 million of 5.125% Series and $1.0 million of 8.00% Series.

Fitchburg is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, Fitchburg may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2010, 2009 and 2008 related to the annual redemption offer were $25,000, $26,000 and $21,200, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2010 is $117,000 per year.

Earnings Per Share

The following table reconciles basic and diluted earnings per share.

(Millions except shares and per share data)	2010	2009	2008
Earnings Available to Common Shareholders	**$ 9.5**	$ 9.9	$ 9.6
Weighted Average Common Shares Outstanding—Basic (000's)	**10,823**	9,647	5,830
Plus: Diluted Effect of Incremental Shares (000's)	**1**	—	—
Weighted Average Common Shares Outstanding—Diluted (000's)	**10,824**	9,647	5,830
Earnings per Share—Basic and Diluted	**$ 0.88**	$ 1.03	$ 1.65

Weighted average options to purchase 33,000, 63,500 and 97,200 shares of common stock were outstanding during 2010, 2009 and 2008, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Additionally, 6,164, 28,963 and 15,985 weighted average non-vested restricted shares for 2010, 2009 and 2008, respectively, were not included in the above computation because the effect would have been antidilutive.

Note 4: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowings under its revolving credit facility. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery, vehicles and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Long-Term Debt Structure and Covenants—The agreements under which the long-term debt of Unitil and its utility subsidiaries, Unitil Energy, Fitchburg, Northern Utilities, and Granite State, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

The long-term debt of Unitil is issued under Unsecured Promissory Notes with negative pledge provisions. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Unitil to issue new long-term debt, the covenants of the existing long-term agreement(s) must be satisfied, including that Unitil have total funded indebtedness less than 70% of total capitalization, and earnings available for interest equal to at least two times the interest charges for funded indebtedness. Each future senior long-term debt issuance of Unitil will rank pari passu with all other senior unsecured long-term debt issuances. The Unitil agreement requires that if Unitil defaults on any other future long-term debt agreement(s), it would constitute a default under its present long-term debt agreement. Furthermore, the default provisions are triggered by the defaults of Unitil Energy and Fitchburg or certain other actions against subsidiary companies in the Unitil System.

Substantially all of the property of Unitil Energy is subject to liens of indenture under which First Mortgage Bonds (FMB) have been issued. In order to issue new FMB, the customary covenants of the existing Unitil Energy Indenture Agreement must be met, including that Unitil Energy have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Unitil Energy agreements further require that if Unitil Energy defaults on any Unitil Energy FMB, it would constitute a default for all Unitil Energy FMB. The Unitil Energy default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

All of the long-term debt of Fitchburg, Northern Utilities and Granite State are issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of long-term debt ranks pari passu with its other senior unsecured long-term debt within that subsidiary. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Fitchburg, Northern Utilities or Granite State to issue new long-term debt, the covenants of the existing long-term agreements of that subsidiary must be satisfied, including that the subsidiary have total funded indebtedness less than 65% of total capitalization. Additionally, to issue new long-term debt, Fitchburg must maintain earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Unitil Energy agreements, the Fitchburg, Northern Utilities and Granite State agreements each require that if that subsidiary defaults on any of its own long-term debt agreements, it would constitute a default under all of that subsidiary's long-term debt agreements. Each of the Fitchburg, Northern Utilities and Granite State default provisions are not triggered by the actions or defaults of Unitil or any of its other subsidiaries.

The Unitil, Unitil Energy, Fitchburg, Northern Utilities and Granite State long-term debt instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets. The Granite State notes are guaranteed by Unitil for the payment of principal, interest and other amounts payable. This guarantee will terminate if Granite State is reorganized and merges with and into Northern Utilities.

At December 31, 2010, there were no restrictions on Unitil's Retained Earnings for the payment of common dividends. Unitil Energy, Fitchburg, Northern Utilities and Granite State pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil's common shareholders.

Debt Repayment and Sinking Funds—The total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $426,643, $393,946, and $363,755 in 2010, 2009, and 2008, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2010 is: 2011 – $462,055; 2012 – $500,405; 2013 – $541,938; and 2014 – $2,486,919; and 2015 – 4,035,633, respectively.

Long-Term Debt Issuances

On March 2, 2010, both Unitil Energy and Northern Utilities closed long-term financings:

(i) Unitil Energy closed $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds have a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

(ii) Northern Utilities closed $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes have a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

Fair Value of Long-Term Debt—Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements. If there were an active market for the Company's debt securities, the fair value of the Company's long-term debt would be estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield for December 2010. The carrying value of the Company's long-term debt at December 31, 2010 is $288.8 million. The fair value of the Company's long-term debt at December 31, 2010 is estimated to be approximately $313.8 million. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

Details on long-term debt at December 31, 2010 and 2009 are shown below:

Long-Term Debt (millions)	December 31, 2010	December 31, 2009
Unitil Corporation Senior Notes:		
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0
Unitil Energy First Mortgage Bonds:		
5.24% Series, Due March 2, 2020	**15.0**	—
8.49% Series, Due October 14, 2024	**15.0**	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0
Fitchburg Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19.0**	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0
Northern Utilities Senior Notes:		
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	30.0
5.29% Senior Notes, Due March 2, 2020	**25.0**	—
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	50.0
Granite State Senior Notes:		
7.15% Senior Notes, Due December 15, 2018	**10.0**	10.0
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**3.8**	4.3
Total Long-Term Debt	**288.8**	249.3
Less: Current Portion	**0.5**	0.4
Total Long-Term Debt, Less Current Portion	**$288.3**	$248.9

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Consistent with regulatory precedent, interest income is recorded on an under-collection of costs, including carrying charges of $0.9 million and $1.1 million in 2010 and 2009, respectively, on deferred storm costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)

	2010	2009	2008
Interest Expense			
Long-term Debt	**$20.0**	$18.2	$12.0
Short-term Debt	**1.7**	2.1	1.3
Regulatory Liabilities	**0.3**	0.3	0.1
Subtotal Interest Expense	**22.0**	20.6	13.4
Interest Income			
Regulatory Assets	**(3.5)**	(3.6)	(2.5)
AFUDC [1] and Other	**(0.4)**	(1.2)	(0.4)
Subtotal Interest Income	**(3.9)**	(4.8)	(2.9)
Total Interest Expense, net	**$18.1**	$15.8	$10.5

[1] AFUDC—Allowance for Funds Used During Construction

Credit Arrangements

Unitil has a revolving credit facility with a group of banks that extends to October 8, 2013. The borrowing limit under the revolving credit facility is $80.0 million. There was $66.8 million and $64.5 million in short-term debt outstanding through bank borrowings under the revolving credit facility at December 31, 2010 and December 31, 2009, respectively. The total amount of credit available under the Company's revolving credit facility was $13.2 million and $15.5 million at December 31, 2010 and December 31, 2009, respectively. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter. As of December 31, 2010 and December 31, 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 8, 2010, the Company entered into the Fourth Amendment Agreement with Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto (the "Fourth Amendment Agreement"), further amending the credit agreement dated as of November 26, 2008 among Unitil, Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto. The credit agreement was previously amended on January 2, 2009, March 16, 2009, and October 13, 2009 to, among other things, increase the maximum borrowings under the facility to $80.0 million. The Fourth Amendment Agreement extends the scheduled termination date of the credit agreement to October 8, 2013 and provides for two conditional one-year extensions subsequent to the October 8, 2013 termination date (if agreed to among the lenders and Unitil). The Fourth Amendment Agreement also provides the Company a mechanism to request an increase in maximum borrowings of $20.0 million (in increments of not less than $5.0 million). The Fourth Amendment Agreement also provides a new letter of credit sub-facility pursuant to which up to $25.0 million of the credit agreement may be used for the purpose of issuing letters of credit for Unitil or its subsidiaries.

The weighted average interest rates on all short-term borrowings were 2.3%, 3.4%, and 3.8% during 2010, 2009, and 2008, respectively.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $11.7 million and $10.0 million outstanding at December 31, 2010 and December 31, 2009, respectively, related to these asset management agreements. The amount of natural gas inventory released in December 2010, which is payable in January 2011, is $3.9 million and recorded in Accounts Payable at December 31, 2010.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2010, 2009 and 2008 amounted to $1.0 million, $1.0 million and $0.6 million respectively. Fitchburg leases its operations facility in Fitchburg, Massachusetts under an operating lease, with a primary term through January 31, 2013. The lease agreement allows for three additional five-year renewal periods at the option of Fitchburg.

The following is a schedule of future operating lease payment obligations and future minimum lease payments under capital leases as of December 31, 2010:

Year Ending December 31, (000's)	Operating Leases	Capital Leases
2011	$1,178	$ 780
2012	1,086	469
2013	727	154
2014	484	60
2015	362	35
2016 – 2020	289	2
Total Payments	**$4,126**	**$1,500**

Guarantees

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2010, there were approximately $36.3 million of guarantees outstanding and the longest term guarantee extends through December 31, 2012. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $3.8 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Note 5: Energy Supply

Natural Gas Supply

Unitil manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and C&I customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors. Many large and some medium C&I customers purchase their supplies from third-party suppliers, while most of Fitchburg's residential and small C&I customers continue to purchase their supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern Utilities purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern Utilities arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of LNG, to truck supplies to each storage facility within Northern Utilities' service territory.

Northern Utilities has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns an LNG storage and vaporization facility. This plant is used principally during peak load periods to augment the supply of pipeline natural gas.

Electric Power Supply

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third-party energy suppliers. As of December 2010, 104 or 70% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 87% of Unitil's largest Massachusetts customers, representing 36% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential, small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100%

of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two two-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

In connection with the restructuring of the electric industry, Unitil Power, Unitil Energy and Fitchburg divested and sold substantially their power supply portfolios consisting of long-term power supply contracts and ownership interests in generation assets. Unitil Power, Unitil Energy and Fitchburg recover in their rates all the costs associated with this divestiture and sale and have secured regulatory approval from the FERC, NHPUC and MDPU, respectively, for the recovery of stranded costs, including long term contract buyout agreements, and other restructuring-related regulatory assets. The companies have a continuing obligation to submit regulatory filings that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Note 6: Commitments and Contingencies

Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2011. The Company continues to believe the suit is without merit and will defend itself vigorously.

Regulatory Matters

Overview (Unitil Energy, Fitchburg, and Northern Utilities)—Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territories at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern

Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next one to four years, is $46.8 million as of December 31, 2010 including $13.3 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Fitchburg—Base Rate Case Filings—On January 14, 2011, Fitchburg filed a petition with the MDPU requesting approval of a comprehensive revenue decoupling proposals and for an increase in its electric and gas distribution rates. The Company's revenue decoupling proposal is modeled closely on proposals already approved by the Department for other gas and electric utilities operating in the Commonwealth of Massachusetts and is intended to facilitate the achievement of important public policy objectives of fostering energy efficiency, conservation and protecting the environment. The proposed rates are scheduled to change in conjunction with the implementation of revenue decoupling and are subject to the review and approval of the MDPU.

In its rate filing the Company made a request for an increase of $7.1 million in its electric distribution rates, including the recovery of deferred emergency storm restoration costs. The Company also proposed a rate-impact mitigation alternative offset, in whole, the electric distribution rate increase with a corresponding decrease in its Transition Charge. The Transition Charge is the means by which Fitchburg recovers its power supply-related stranded costs and other restructuring-related regulatory assets, discussed above. Any offsetting decrease in the Transition Charge would allow for the recovery of the restructuring related stranded costs over an extended term. The Company's filing included a request for an increase of $4.4 million in its gas distribution rates. The MDPU issued an order suspending and deferring the use of the rates until August 2, 2011, pending an investigation and analysis of the Company's filing.

Granite State Gas Transmission, Inc.—Base Rate Case Filing—On June 29, 2010, Granite State filed a base transportation rate increase of $2.3 million in annual revenue with the FERC, which is Granite State's first request for a rate change since its last general rate case in 1997. On July 30, 2010, the FERC ordered the rate increase to be effective on January 1, 2011, subject to refund and hearing and settlement procedures. On November 30, 2010, a settlement was filed on behalf of Granite State and all intervenors in the proceeding, resolving all issues in the docket. The settlement provides for an increase of approximately $1.7 million in annual revenue, based on new gas transportation rates to be effective January 1, 2011. The settlement was approved by the FERC on January 31, 2011.

Unitil Energy Rate Case Filing—On April 15, 2010, Unitil Energy filed a proposed base rate increase of $10.1 million, an increase of 6.5 percent above present rates. In addition, Unitil Energy's filing also included a proposed long-term rate plan establishing future rate step adjustments for utility plant investments and enhanced reliability and vegetation management program expenditures. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy of $5.2 million (annual) effective July 1, 2010 which is being collected by a uniform per kilowatt-hour (kWh) surcharge of $0.00438 on each of Unitil Energy's current rate schedules. Once permanent rates are approved by the NHPUC, they

will be reconciled to the date temporary rates were ordered, July 1, 2010. The Company is currently engaged in settlement proceedings regarding the permanent rate level and a long-term rate plan. A hearing in this matter is scheduled for early February 2011.

Major Wind Storm—On February 25, 2010, a significant wind storm struck portions of the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including approximately 85% of the Unitil Energy's customers. The Company spent approximately $7.4 million for the repair and replacement of electric distribution systems damaged during the storm, including $1.5 million related to capital construction and $5.9 million which has been deferred as a regulatory asset. Unitil Energy, in its base rate case filing discussed above, has requested recovery in rates for the costs associated with the emergency repair of its electric distribution system for damage caused by this storm.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region. The Company spent approximately $24.0 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.6 million related to capital construction and $15.4 million which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. If the Company is unable to recover a significant amount of these deferred storm costs, or if the Company's recovery of these costs is significantly delayed, then the Company's financial condition or results of operations could be adversely affected.

On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. On September 24, 2010, the NHPUC issued its final order in this matter and closed its investigation, accepting the NHPUC Staff's report finding that Unitil Energy had acted reasonably.

On November 9, 2009, the NHPUC granted Unitil Energy's petition to defer and record as a regulatory asset costs associated with electric distribution system damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's pending base rate case. The order clarified that the issues of the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are to be reviewed in the rate case. As of December 31, 2010, Unitil Energy has deferred approximately $2.2 million associated with the repair of its electric distribution system for future recovery in rates.

On December 30, 2009, the MDPU approved Fitchburg's petition to defer and record as a regulatory asset costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. The order of approval made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and confirmed that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. As of December 31, 2010, Fitchburg has deferred approximately $13.2 million associated with the repair of its electric distribution system for future recovery in rates.

The MDPU conducted an investigation of Fitchburg's preparation for, and response to, the December 2008 Ice Storm during the first half of 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service, and ordered several remedial actions. First, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices. The management audit, which is being performed by Jacobs Consultancy, Inc., began in the fourth quarter of 2010. Second, the MDPU directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. All of these operational and capital improvements have either been completed or are being implemented, and remain subject to MDPU review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

Fitchburg—Electric Operations—On November 24, 2010, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery continues through a Transition Charge Surcharge of $0.00400 per kWh. Changes to the Pension/PBOP Adjustment, Residential Assistance Adjustment Factor, and Net Metering Recovery Surcharge were proposed in other proceedings. The rates were approved effective January 1, 2011, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2009 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting regulations concerning the items required by House Bill 4329. On July 30, 2010, the MDPU approved Fitchburg's electric and gas Emergency Response Plans.

Fitchburg—Gas Operations—On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement order to the Massachusetts SJC. Fitchburg believes that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. The Company filed its Initial brief in this matter on January 10, 2011. This appeal remains pending before the Massachusetts SJC.

Fitchburg—Other—On February 11, 2009, the Massachusetts SJC issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The Massachusetts SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Massachusetts SJC, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, special tariffs to allow the net metering of customer-owned renewable generation, and terms and conditions for purchasing supplier receivables. Three year energy efficiency investment plans, plans to establish smart grid pilot programs, and net metering tariffs have been approved by the MDPU. Proposals to purchase long-term contracts for renewable energy and terms and conditions for purchasing supplier receivables are under review in a separately designated docket.

On March 1, 2010, Fitchburg submitted its annual filing to the MDPU of the 2009 Service Quality Reports for both its gas and electric divisions. On October 20, 2010, the MDPU issued its order with respect to Fitchburg's gas division's Report and noted that Fitchburg met or exceeded its established benchmarks in all Service Quality measures, that Fitchburg's performance was consistent with the MDPU's Service Quality Guidelines and Fitchburg's Service Quality plan. An order on Fitchburg's electric division's Service Quality plan has not yet been issued and the matter remains pending.

Unitil Energy—Other—In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources (DER). An order approving a settlement agreement for a time-of-use pilot program was issued on February 26, 2010. On June 11, 2010, the NHPUC issued an order on the remaining two proposed projects and cost recovery. The NHPUC denied one of the two projects, citing that the costs outweighed the benefits but found the other project to be in the public interest. On November 1, 2010 Unitil Energy filed adjustments to base distribution rates to collect actual costs associated with authorized DER projects. This matter remains pending.

On June 17, 2010, Unitil Energy made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2010, including reconciliation of prior year costs and revenues. On July 30, 2010, the NHPUC approved the rate filing and reconciliation.

Northern Utilities—On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation (NOPVs) of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's consolidated balance sheet at December 31, 2010 was $0.7 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in portions of Northern Utilities' Maine service areas. In an order issued on July 30, 2010, the MPUC approved a Settlement Agreement resolving this matter, filed on behalf of Northern Utilities, the Maine Office of the Public Advocate, and several state legislator intervenors, which was filed with the MPUC on July 6, 2010. Under the Agreement, Northern Utilities will proceed with a comprehensive upgrade and replacement program (the Program), which will provide for the systematic replacement of cast iron, wrought iron and bare steel pipe in Northern Utilities' natural gas distribution system in Portland and Westbrook, Maine and the conversion of the system to intermediate pressure. The Agreement establishes the objective of completing the Program by the end of the 2024 construction season. Under the Agreement, the parties agreed to support a cost recovery mechanism that will provide for the timely recovery of prudently-incurred costs of the Program. The features of this cost recovery mechanism will be finalized during Northern Utilities' next base rate case proceeding, which is anticipated to be filed in early 2011.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. In January 2011, Fitchburg settled with the remaining insurance carriers for approximately $2.0 million and expects to receive these payments in the first quarter of 2011. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are shared equally between Fitchburg and its gas customers.

Fitchburg is in the process of developing long-range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2010 and 2009 in Environmental Obligations are accrued liabilities totaling $12.0 million and $12.0 million, respectively, related to estimated future clean up costs for permanent remediation of the Sawyer Passway site. A corresponding Regulatory Asset was recorded to reflect that the recovery of this environmental remediation cost is probable through the regulatory process. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

Northern Utilities Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Include in the Company's Consolidated Balance Sheets at December 31, 2010 and 2009 are current and non-current accrued liabilities totaling $2.6 million and $2.5 million, respectively, associated with Northern Utilities environmental remediation obligations for these former MGP sites. A corresponding Regulatory Asset was recorded to reflect that the recovery of these environmental remediation cost is probable through the regulatory process.

The Company's ultimate liability for future environmental remediation costs, including MGP site costs, may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

The following table shows the balances and activity in the Company's liability for Environmental Obligations for 2010.

ENVIRONMENTAL OBLIGATIONS

(Millions)	December 31, 2010	December 31, 2009
Total Environmental Obligations—Balance at Beginning of Period	**$14.5**	$12.7
Changes in Estimates	**0.2**	1.8
Liabilities Assumed	**—**	—
Payments/Reductions	**0.1**	—
Total Environmental Obligations—Balance at End of Period	**14.6**	14.5
Less: Current Portion [(1)]	**0.1**	0.2
Environmental Obligations—noncurrent—Balance at End of Period	**$14.5**	$14.3

(1) Reflects amounts included in Other Current Liabilities on the Company's Consolidated Balance Sheets.

Note 7: Bad Debts

Unitil's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. In 2010, 2009 and 2008, the Company recorded provisions for the energy commodity portion of bad debts of $1.4 million, $1.9 million and $2.1 million, respectively. These provisions were recognized in Purchased Electricity and Purchased Gas expense as the associated electric and gas utility revenues were billed. Purchased Electricity and Purchased Gas costs are recovered from customers through periodic rate reconciling mechanisms.

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2008—2010 ($ millions):

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	(a) Other	Provision	Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2010						
Electric	**$1.7**	**$ —**	**$2.0**	**$0.2**	**$2.1**	**$1.8**
Gas	**0.7**	**—**	**2.5**	**0.4**	**2.9**	**0.7**
Other	**0.1**	**—**	**—**	**—**	**—**	**0.1**
	$2.5	**$ —**	**$4.5**	**$0.6**	**$5.0**	**$2.6**
Year Ended December 31, 2009						
Electric	$1.1	$ —	$2.3	$0.2	$1.9	$1.7
Gas	1.8	0.5	1.4	0.3	3.3	0.7
Other	0.1	—	—	—	—	0.1
	$3.0	$0.5	$3.7	$0.5	$5.2	$2.5
Year Ended December 31, 2008						
Electric	$1.0	$ —	$2.2	$0.2	$2.3	$1.1
Gas	0.2	1.4	1.4	0.2	1.4	1.8
Other	0.1	—	—	—	—	0.1
	$1.3	$1.4	$3.6	$0.4	$3.7	$3.0

(a) Includes Allowance for Doubtful Accounts of Northern Utilities and Granite State, which were acquired on December 1, 2008.

Note 8: Income Taxes

Provisions for Federal and State Income Taxes reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2010, 2009 and 2008 are shown in the table below:

	($000's) 2010	2009	2008
Current Federal Tax Provision (Benefit)			
Current Benefit of Operating Loss Carrybacks	**$ (6,026)**	$(3,226)	$(2,914)
Total Current Federal Tax Provision (Benefit)	**(6,026)**	(3,226)	(2,914)
Deferred Federal Tax Provision (Benefit)			
Utility Plant Differences	**11,821**	8,716	5,159
Net Operating Loss Carryforwards	**(5,520)**	—	—
Regulatory Assets and Liabilities	**3,338**	(1,308)	1,534
Other, net	**(480)**	(120)	121
Total Deferred Federal Tax Provision (Benefit)	**9,159**	7,288	6,814
Total Federal Tax Provision	**3,133**	4,062	3,900
State			
Current	**28**	1,578	123
Deferred	**1,303**	(218)	592
Total State Tax Provision	**1,331**	1,360	715
Total Provision for Federal and State Income Taxes	**$ 4,464**	$ 5,422	$ 4,615

The differences between the Company's provisions for Income Taxes, including the provision for Business Enterprise taxes, and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2010	2009	2008
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**6**	6	5
Utility Plant Differences	**(7)**	(3)	(6)
Other, Net	**(1)**	(1)	(1)
Effective Income Tax Rate	**32%**	36%	32%

Temporary differences, including the effect of deferred tax accounting on utility plant differences and accrued revenue regulatory assets, which gave rise to deferred tax assets and liabilities, are shown below:

Deferred Income Taxes (000's)	2010	2009
Depreciation and Utility Plant	**$ 44,608**	$ 30,318
Net Operating Loss Carryforwards	**(8,567)**	—
AMT Tax Credit Carryforwards	**(1,366)**	—
Regulatory Assets/Liabilities & Mechanisms	**33,421**	29,094
Retirement Benefit Obligations	**(25,155)**	(22,537)
Other, net	**883**	2,896
Total Deferred Income Tax Liabilities	**$ 43,824**	$ 39,771

The Company is subject to Federal and State income taxes as well as various other business taxes. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining the current and deferred tax assets and liabilities. The Company's current and deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. Periodically, the Company assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Concurrent with filing its 2009 Federal income tax return in September of 2010, the Company changed its method of tax accounting for certain construction-related costs previously capitalized as depreciable assets, to account for those expenditures as repairs expense deductions under Sections 162 and 263(a) of the Internal Revenue Code (IRC). In applying the new tax accounting method, certain costs which were previously capitalized and recognized as depreciation deductions over various useful lives for tax accounting purposes are now to be deducted in the year incurred.

The Company applied the tax accounting method change retroactively for additional deductions of $23.9 million in its Federal Income Tax return filing for the year ended December 31, 2009 which resulted in a 2009 net operating loss (NOL) of $26.5 million. As a result, the Company recognized NOL carrybacks against its Federal Income Tax returns for the years ended December 31, 2004, 2005, and 2007 in the amounts of $1.1 million, $12.8 million, and $9.6 million, respectively. The carryback of the 2009 NOL resulted in current tax refunds of $7.5 million and remaining unused NOL and Alternative Minimum Tax (AMT) credit carryforwards of $3.0 million and $1.4 million respectively.

According to IRC rules, NOL refunds in excess of $2.0 million fall under the jurisdiction of the Joint Committee of Congress (Joint Committee) and are subject to review by the Internal Revenue Service (IRS) and attorneys of the Joint Committee. The Company expects to receive notice of examination for the 2009 Federal Income Tax return filings under the Joint Committee rules. The Company remains subject to examination by Federal, Maine, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2009; December 31, 2008; and December 31, 2007.

In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized NOL carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of $5.0 million and $6.7 million, respectively. These NOL carrybacks resulted in a refund to the Company of $4.0 million which was received in November 2009. As a result, on December 30, 2009, the Company received notice that its Federal Income Tax return filings for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 were under examination by the IRS. The IRS has performed all fieldwork procedures and the company and the IRS have entered into a settlement, pending approval of the Joint Committee, for certain timing items deducted in previous years to be deducted in the Federal Income Tax return filings for year ended December 31, 2009. As a result of the settlement, in November 2010 the Company paid $0.2 million and $1.5 million for tax years 2006 and 2007, respectively. The amount paid included interest of $0.1 million and $0.1 million for tax years 2006 and 2007, respectively which is recorded in Interest Expense, Net for 2010 in the Consolidated Statements of Earnings.

In total at December 31, 2010, the Company had generated NOL carryforwards for income tax purposes of $8.5 million that will expire in 2011 through 2030, if not utilized. In addition, at December 31, 2010, the Company had $1.4 million of AMT credit carryforwards to offset future AMT indefinitely.

The Company evaluated its tax positions at December 31, 2010 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by the FASB Codification is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months.

Note 9: Segment Information

Unitil reports four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capitol regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine.

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transmission services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies. Unitil Resources and Usource are included in the Non-Regulated column below.

Unitil Realty, Unitil Service and the holding company are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries' use.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes and preferred stock dividends. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on cost allocation factors included in rate applications approved by the NHPUC, MDPU, and MPUC. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2010, 2009 and 2008 (Millions):

Year Ended December 31, 2010	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$203.7**	**$150.1**	**$ —**	**$4.6**	**$358.4**
Interest Income	**3.2**	**0.5**	**0.2**	**0.1**	**4.0**
Interest Expense	**9.6**	**10.5**	**2.0**	**—**	**22.1**
Depreciation & Amortization Expense	**13.9**	**14.2**	**0.8**	**—**	**28.9**
Income Tax Expense (Benefit)	**3.7**	**(0.7)**	**0.5**	**1.0**	**4.5**
Segment Profit (Loss)	**8.0**	**1.4**	**(1.4)**	**1.5**	**9.5**
Segment Assets	**377.7**	**370.8**	**5.7**	**5.4**	**759.6**
Capital Expenditures	**19.8**	**27.4**	**2.4**	**—**	**49.6**
Year Ended December 31, 2009					
Revenues	$209.9	$152.8	$ —	$4.3	$367.0
Interest Income	3.6	0.5	0.7	—	4.8
Interest Expense	9.1	9.7	1.8	—	20.6
Depreciation & Amortization Expense	14.0	12.8	0.6	—	27.4
Income Tax Expense (Benefit)	2.4	1.9	0.1	1.0	5.4
Segment Profit (Loss)	4.9	3.3	0.1	1.6	9.9
Segment Assets	365.6	349.7	7.3	2.6	725.2
Capital Expenditures	27.7	30.0	1.0	—	58.7
Year Ended December 31, 2008					
Revenues	$227.5	$ 56.9	$ —	$3.8	$288.2
Interest Income	2.2	0.1	0.3	—	2.6
Interest Expense	8.7	2.3	2.1	—	13.1
Depreciation & Amortization Expense	13.1	5.2	0.8	—	19.1
Income Tax Expense (Benefit)	1.9	2.6	(0.1)	0.2	4.6
Segment Profit (Loss)	5.2	4.3	(0.2)	0.3	9.6
Segment Assets	372.2	350.9	9.1	1.0	733.2
Capital Expenditures	19.7	7.6	1.0	—	28.3

Note 10: Retirement Benefit Plans

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan)—The Pension Plan is a defined benefit pension plan. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service. In September 2009, the Company amended the Pension Plan as follows:
  - The Pension Plan was closed to non-union employees hired on or after January 1, 2010.

- All non-union employees hired before January 1, 2010 had a choice of either:
    - Remaining in the Pension Plan with the existing set of benefits, or
    - Electing to move to Unitil Corporation's enhanced Tax Deferred Savings and Investment Plan. Non-union employees who elected this option received a frozen benefit from the existing Pension Plan for all of the benefits that they had accrued to December 31, 2009. This frozen benefit will not grow with future salary increases or future service. Non-union employees who elected this option will receive an enhanced employer matching contribution as well as a Company contribution in the Unitil Corporation Tax Deferred Savings and Investment Plan.
    - Union employees were not affected by this amendment.

In September 2010, the Company amended the Pension Plan as follows:

- The Pension Plan was closed to United Steelworker Local 12012-6 employees hired on or after January 1, 2011.
- All United Steelworker Local 12012-6 employees hired before January 1, 2011 had a choice of either:
    - Remaining in the Pension Plan with the existing set of benefits, or
    - Electing to move to Unitil Corporation's enhanced Tax Deferred Savings and Investment Plan. The United Steelworker Local 12012-6 employees who elected this option received a frozen benefit from the existing Pension Plan for all of the benefits that they had accrued to December 31, 2010. This frozen benefit will not grow with future salary increases or future service. The employees who elected this option will receive an enhanced employer matching contribution as well as a Company contribution in the Unitil Corporation Tax Deferred Savings and Investment Plan.
    - All other union employees were not affected by this amendment.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan)—The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan. In 2009, the Company made the following changes to the PBOP Plan.

Changes to Utility Workers Union of America Local 341 Benefits

A new Collective Bargaining Agreement ("Agreement") was entered into between Northern Utilities, Inc., Granite State Gas Transmission, Inc. and Utility Workers Union of America Local 341 ("UWUA") for the period April 1, 2009 through March 31, 2012. Included in the Agreement were changes to retiree medical benefits under the Plan. These changes are as follows:

- Retirees under sixty-five (65) years and their dependents will be covered by the medical benefits provided by the PBOP Plan. Early retirees will be responsible for contributing 20% of the premium for medical insurance for themselves and their dependents until age sixty-five (65).
- Retirees over sixty-five (65) years will be covered by a Supplement to Medicare Plan and will be responsible for a 20% premium cost sharing.
- For all employees hired on or after April 1, 2009, no post-65 retiree medical coverage will be provided.
- The Company is to determine post-65 drug coverage to be offered to all future retirees eligible for retiree medical.

These above-referenced retiree medical provisions were effective January 1, 2010.

Changes to United Steelworker Local 12012-6 Benefits

A new Collective Bargaining Agreement ("Agreement") was entered into between Northern Utilities, Inc. and United Steelworker Local 12012-6 ("USW") for the period June 6, 2010 through June 5, 2014. Included in the Agreement were changes to retiree medical benefits under the Plan. These changes are as follows:

- Retirees under sixty-five (65) years and their dependents will be covered by the medical benefits provided by the PBOP Plan. Early retirees will be responsible for contributing 20% of the premium for medical insurance for themselves and their dependents until age sixty-five (65).
- Retirees over sixty-five (65) years will be covered by a Supplement to Medicare Plan and will be responsible for a 20% premium cost sharing.
- For all employees hired on or after June 6, 2010, no post-65 retiree medical coverage will be provided.

These above-referenced retiree medical provisions were effective June 6, 2010.

Changes to Non-Union Employee Benefits

In September 2009, the Company announced the following PBOP Plan changes, effective January 1, 2010, for non-union employees:

- Employees who retire on or after January 1, 2010 will pay 20% of the cost of their retiree medical benefits.
- Employees who retire on or after January 1, 2010 will not receive any cash payments towards their Medicare premiums.
- Employees who are hired on or after January 1, 2010 will only be provided with company subsidized medical insurance until they reach age 65 and will not receive a Medicare supplement plan after age 65.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP)—The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

Effective with the acquisitions of Northern Utilities and Granite State, the Company assumed the assets and obligations of the Northern Utilities and Granite State pension plans with respect to active union employees. All other active employees of Northern Utilities and Granite State effectively became members of the Company's Pension Plan as of the acquisitions closing date.

Certain employees of Northern Utilities qualified for participation in the Company's PBOP Plan effective with the acquisition closing date.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan costs for years ended December 31:	2010	2009	2008
Discount Rate [1]	**5.75%**	6.25%	6.00%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.50%**	8.00%	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017	2017
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 728**	$ 735	$ 675
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$ (565)**	$ (576)	$ (531)

(1) As a result of the changes to the PBOP Plan in September 2009 discussed above, the Company was required to update the discount rate used in determining the PBOP Plan costs for the remainder of 2009. Based on the market rates for long-term bonds at that time, the Company assumed a discount rate of 5.50% for the PBOP Plan from September through December of 2009.

Used to Determine Benefit Obligations at December 31:

Discount Rate	**5.35%**	5.75%	6.25%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.00%**	7.50%	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2017	2017
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 7,530**	$ 5,887	$ 6,084
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$(5,997)**	$(4,704)	$(4,890)

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2010, 2009 and 2008, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000, $300,000 and $200,000, respectively, in the Net Periodic Benefit Cost (NPBC). The Rate of Compensation Increase assumption used for 2010, 2009 and 2008 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan			PBOP Plan			SERP		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Service Cost	**$ 2,608**	$ 2,282	$ 1,979	**$ 1,466**	$ 1,417	$ 1,447	**$285**	$217	$150
Interest Cost	**4,457**	4,294	3,800	**2,016**	2,269	2,212	**227**	181	126
Expected Return on Plan Assets	**(4,181)**	(4,432)	(4,390)	**(599)**	(440)	(325)	**—**	—	—
Prior Service Cost Amortization	**253**	264	119	**1,579**	1,634	1,390	**2**	(2)	(1)
Transition Obligation Amortization	**—**	—	—	**21**	21	21	**—**	—	—
Curtailment Loss	**41**	32	—	**—**	—	—	**—**	—	—
Actuarial Loss Amortization	**2,406**	1,598	1,274	**—**	—	—	**133**	70	24
Sub-total	**5,584**	4,038	2,782	**4,483**	4,901	4,745	**647**	466	299
Amounts Capitalized and Deferred	**(2,240)**	(1,409)	(893)	**(1,183)**	(1,642)	(1,872)	**—**	—	—
NPBC Recognized	**$ 3,344**	$ 2,629	$ 1,889	**$ 3,300**	$ 3,259	$ 2,873	**$647**	$466	$299

The estimated amortizations related to Actuarial Loss and Prior Service Cost included in the Company's Retirement plan costs over the next fiscal year is $3.4 million, $1.7 million and $0.1 million for the Pension, PBOP and SERP plans, respectively.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2010, 2009 and 2008 before capitalization and deferral was $5.6 million, $4.0 million and $2.8 million, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2010, 2009 and 2008 would have been $6.2 million, $6.3 million and $2.9 million respectively.

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan		PBOP Plan		SERP	
Change in Plan Assets:	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Plan Assets at Beginning of Year	**$ 47,082**	$ 39,124	**$ 6,306**	$ 4,361	**$ —**	$ —
Actual Return on Plan Assets	**5,901**	8,017	**922**	874	**—**	—
Employer Contributions	**4,302**	4,227	**3,482**	2,800	**53**	53
Participant Contributions	**—**	—	**—**	2	**—**	—
Acquired Plan Assets	**—**	(544)	**—**	—	**—**	—
Benefits Paid	**(3,185)**	(3,742)	**(1,848)**	(1,731)	**(53)**	(53)
Plan Assets at End of Year	**$ 54,100**	$ 47,082	**$ 8,862**	$ 6,306	**$ —**	$ —
Change in PBO:						
PBO at Beginning of Year	**$ 79,288**	$ 70,386	**$ 35,694**	$ 37,655	**$ 3,979**	$ 2,930
Service Cost	**2,608**	2,282	**1,466**	1,417	**285**	217
Interest Cost	**4,457**	4,294	**2,016**	2,269	**227**	181
Participant Contributions	**—**	—	**—**	2	**—**	—
Plan Amendments	**—**	—	**1,683**	(2,382)	**138**	—
Estimated Acquired Obligations	**—**	—	**—**	—	**—**	—
Curtailment Gain	**(1)**	(599)	**—**	—	**—**	—
Benefits Paid	**(3,185)**	(3,742)	**(1,848)**	(1,731)	**(53)**	(53)
Actuarial (Gain) or Loss	**6,226**	6,667	**4,333**	(1,536)	**(313)**	704
PBO at End of Year	**$ 89,393**	$ 79,288	**$ 43,344**	$ 35,694	**$ 4,263**	$ 3,979
Funded Status: Assets vs PBO	**$(35,293)**	$(32,206)	**$(34,482)**	$(29,388)	**$(4,263)**	$(3,979)

The Company has recorded on its consolidated balance sheets as a liability the underfunded status of their retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets of $47.1 million and $43.7 million at December 31, 2010 and 2009, respectively, to recognize the future collection of these plan obligations in electric and gas rates.

The Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $78.4 million and $69.0 million as of December 31, 2010 and 2009, respectively. The ABO for the SERP was $0.5 million and $0.5 million as of December 31, 2010 and 2009, respectively. For the PBOP Plan, the ABO and PBO are the same.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in

the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 – 2010 plan years. The Company's Pension Plan was 80% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2010 which resulted in a shortfall of $10.2 million. This shortfall is being amortized over seven years with annual payments of $1.7 million, beginning in 2010. The $1.7 million payment for 2010 is included in the Employer Contributions amount shown in the table below. On June 25, 2010, the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 (Relief Act) was signed into law. The pension relief portion of the Relief Act provides two alternative shortfall amortization periods to the seven year amortization period required under the PPA. The Company has evaluated the two alternative shortfall amortization periods under the Relief Act and made the decision to continue with the seven year amortization period. The Company, along with its subsidiaries, expects to continue to make contributions to its Pension Plan in 2011 and future years at minimum required and discretionary funding levels consistent with the amounts recovered in the distribution utilities' rates for these Pension Plan costs.

The following table represents employer contributions and benefit payments ($000's). There were no participant contributions.

	Pension Plan			PBOP Plan			SERP		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Employer Contributions	**$4,302**	$4,227	$2,800	**$3,482**	$2,800	$2,700	**$53**	$53	$59
Benefit Payments	**$3,185**	$3,742	$2,796	**$1,848**	$1,731	$1,699	**$53**	$53	$59

The following table represents estimated future benefit payments ($000's).

	Estimated Future Benefit Payments		
	Pension	**PBOP**	**SERP**
2011	$ 3,740	$ 1,512	$ 52
2012	3,958	1,613	51
2013	4,144	1,710	320
2014	4,365	1,824	318
2015	4,525	1,939	317
2016 - 2020	$26,922	$11,327	$1,555

The Expected Long-Term Rate of Return on Pension Plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on Pension Plan assets is based on target investment allocation of 57% in common stock equities and 43% in fixed income securities. The Company's Expected Long-Term Rate of Return on PBOP Plan assets is based on target investment allocation of 55% in common stock equities and 45% in fixed income securities. The actual investment allocations are shown in the tables below.

Pension Plan	**Target Allocation 2011**	**Actual Allocation at December 31,**		
		2010	**2009**	**2008**
Equity Securities	57%	**58%**	59%	54%
Debt Securities	43%	**42%**	40%	35%
Other	0%	**0%**	1%	11%
Total		**100%**	100%	100%

PBOP Plan	**Target Allocation 2011**	**Actual Allocation at December 31,**		
		2010	**2009**	**2008**
Equity Securities	55%	**56%**	56%	56%
Debt Securities	45%	**44%**	44%	44%
Total		**100%**	100%	100%

(1) Represents investments in Money Market Funds.

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2010. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 5 – 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The FASB Codification defines fair value, and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under the FASB Codification are described below:

Level 1 – Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Valuations based on quoted prices in markets that are not active or for which all significant inputs are observable, either directly or indirectly.

Level 3 – Prices or valuations that require inputs that are both significant to the fair value measurement and unobservable.

To the extent that valuation is based on models or inputs that are less observable or unobservable in the market, the determination of fair value requires more judgment. Accordingly, the degree of judgment exercised by the Company in determining fair value is greatest for instruments categorized in Level 3. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Fair value is a market-based measure considered from the perspective of a market participant rather than an entity-specific measure. Therefore, even when market assumptions are not readily available, the Company's own assumptions are set to reflect those that market participants would use in pricing the asset or liability at the measurement date. The Company uses prices and inputs that are current as of the measurement date, including during periods of market dislocation. In periods of market dislocation, the observability of prices and inputs may be reduced for many instruments. This condition could cause an instrument to be reclassified from Level 1 to Level 2 or from Level 2 to Level 3.

Valuation Techniques

There have been no changes in the valuation techniques used during the current period.

Assets measured at fair value on a recurring basis for the Pension Plan as of December 31, 2010 and 2009 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2010**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Pension Plan Assets:				
Mutual Funds:				
Balanced Funds	$31,625	$31,625	$—	$—
Fixed Income Funds	22,475	22,475		
Total Assets	$54,100	$54,100	$—	$—

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Pension Plan Assets:				
Mutual Funds:				
Balanced Funds	$27,706	$27,706	$—	$—
Fixed Income Funds	18,961	18,961	—	—
Total Mutual Funds	$46,667	$46,667	—	—
Cash Equivalents	415	415	—	—
Total Assets	$47,082	$47,082	$—	$—

Assets measured at fair value on a recurring basis for the PBOP Plan as of December 31, 2010 and 2009 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2010**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$3,936	$3,936	$—	$—
Index Funds	3,580	3,580		
Balanced Funds	1,346	1,346		
Total Assets	$8,862	$8,862	$—	$—

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$2,776	$2,776	$—	$—
Index Funds	2,582	2,582		
Balanced Funds	948	948		
Total Assets	$6,306	$6,306	$—	$—

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company common stock fund.

In September 2009, the Company amended the Plan as follows:

For current non-union employees who elect to stay with the Company's existing Pension Plan, there will be no changes in the 401(k) Plan. For those employees, the Company will continue to match contributions, with a maximum matching contribution of 3% of current compensation and those participants will be 100% vested in these company matching contributions once they have completed three years of service.

For non-union employees who are hired on or after January 1, 2010, and for non-union employees who elect to move from the Company's existing Pension Plan and accept a frozen pension benefit, the Company will provide the following enhancements to the 401(k) Plan:

- The Company will contribute 4% of base pay each year, regardless of whether or not the non-union employee elects to contribute to the 401(k) Plan.
- The Company will increase the matching contributions from 3% of base pay to 6% of base pay. This will be a 100% match of the first 6% of the non-union employee's contributions.
- All Company contributions will be 100% vested at all times.
- New non-union employees will be automatically enrolled in the 401(k) Plan following the completion of 1,000 hours of service, with the automatic contribution rate of 3%. This contribution rate will automatically increase by 1% on January 1 of each year until the non-union employee's contribution is 10% of pay. Non-union employees may elect to opt-out of the automatic enrollment and/or automatic increase features of the enhanced 401(k) Plan.

The Company's contributions to the 401(k) Plan were $980,000, $671,000 and $542,000 for the years ended December 31, 2010, 2009, and 2008, respectively.

Note 11: Quarterly Financial Information (unaudited; Millions, except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding and the impact of additional common share issuances. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2010	2009	2010	2009	2010	2009	2010	2009
Total Operating Revenues	**$113.0**	$135.6	**$ 71.4**	$ 71.5	**$ 76.1**	$ 70.4	**$ 97.9**	$ 89.5
Operating Income	**$ 10.9**	$ 13.9	**$ 2.7**	$ 4.2	**$ 4.6**	$ 3.4	**$ 9.8**	$ 4.6
Net Income (Loss) Applicable to Common	**$ 6.5**	$ 9.1	**$ (2.1)**	$ 0.2	**$ (0.1)**	$ (0.6)	**$ 5.2**	$ 1.2
	Per Share Data:							
Earnings Per Common Share	**$ 0.61**	$ 1.14	**$ (0.19)**	$ 0.03	**$ (0.01)**	$ (0.06)	**$ 0.48**	$ 0.11
Dividends Paid Per Common Share	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

On July 21, 2010, the Company was notified that effective July 20, 2010, McGladrey & Pullen, LLP (McGladrey) acquired certain assets of Caturano and Company, Inc. (formerly Caturano and Company, P.C.), the Company's independent registered public accounting firm (Caturano) and substantially all of the officers and employees of Caturano joined McGladrey. As a result, Caturano resigned as the independent registered public accounting firm for the Company and McGladrey was appointed by the Audit Committee of the Company's Board of Directors as the Company's new independent registered public accounting firm on September 22, 2010.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, conducted an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of December 31, 2010. Based on this evaluation, the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded as of December 31, 2010 that the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f).

Under the supervision and with the participation of management, including the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, Unitil management has evaluated the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, based upon criteria established in the "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, Unitil management concluded that Unitil's internal control over financial reporting was effective as of December 31, 2010.

McGladrey and Pullen, LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2010, as stated in their report which appears in Part II, Item 8 herein.

Changes in Internal Control over Financial Reporting

There have been no changes in Unitil's internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fiscal quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, Unitil's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers of the Registrant and Corporate Governance

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K and in the "Proposal I: Election of Directors" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011. Information regarding the Company's Audit Committee is set forth in the "Corporate Governance and Policies of the Board" and "Committees of the Board" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Compensation Discussion and Analysis" and "Compensation of Named Executive Officers" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the "Beneficial Ownership" and "As to the Election of Directors" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011, as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this Item is set forth in the "Transactions with Related Persons" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Reports of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2010 and 2009
- Consolidated Statements of Earnings for the years ended December 31, 2010, 2009, and 2008
- Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009, and 2008
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2010, 2009, and 2008
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	Articles of Amendment to the Articles of Incorporation Filed on September 23, 2008.	Exhibit 3.3 to Form S-3/A dated November 25, 2008
3.4	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.5	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.6	Articles of Exchange of CECo, E&H, and the Company—Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.7	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (Fitchburg) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.8	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002

Exhibit Number	Description of Exhibit	Reference*
4.2	Fitchburg Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.3	Fitchburg Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.4	Fitchburg Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.5	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.6	Fitchburg Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.7	Fitchburg Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
4.8	Thirteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of September 26, 2006.	**
4.9	Unitil Corporation Note Purchase Agreement, dated as of May 2, 2007, for the 6.33% Senior Notes due May 1, 2022.	**
4.10	Northern Utilities Note Purchase Agreement, dated as of December 3, 2008, for the 6.95% Senior Notes, Series A due December 3, 2018 and the 7.72% Senior Notes, Series B due December 3, 2038.	Exhibit 4.1 to Form 8-K dated December 3, 2008
4.11	Granite State Note Purchase Agreement, dated as of December 15, 2008, for the 7.15% Senior Notes due December 15, 2018.	Exhibit 99.1 to Form 8-K dated December 15, 2008
4.12	Northern Utilities Note Purchase Agreement, dated as of March 2, 2010, for the 5.29% Senior Notes, due March 2, 2020.	Exhibit 4.1 to Form 8-K dated March 2, 2010
4.13	Fourteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of March 2, 2010.	Exhibit 4.4 to Form 8-K dated March 2, 2010
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 8-K dated June 19, 2008
10.5***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.3 to Form 8-K dated June 19, 2008
10.6***	Amended and Restated Unitil Corporation Supplemental Executive Retirement Plan effective as of December 31, 2007.	Exhibit 10.4 to Form 8-K dated June 19, 2008

Exhibit Number	Description of Exhibit	Reference*
10.7***	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.8***	Amended and Restated Unitil Corporation Management Incentive Plan effective as of June 19, 2008 as further amended on December 1, 2008.	Exhibit 10.8 to Form 10-K for 2008
10.9	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.10***	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.11	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.12	Unitil Corporation Tax Deferred Savings and Investment Plan—Trust Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2004
10.13***	Amended and Restated Employment Agreement effective as of November 1, 2009 by and between Unitil Corporation and Robert G. Schoenberger.	Exhibit 10.1 to Form 8-K dated September 23, 2009
10.14	Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008.	Exhibit 10.1 to Form 8-K dated November 26, 2008
10.15	Amendment Agreement dated as of January 2, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008.	Exhibit 10.1 to Form 8-K dated January 2, 2009
10.16	Amendment Agreement dated as of October 13, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008.	Exhibit 10.1 to Form 8-K dated October 13, 2009
10.17	Fourth Amendment Agreement dated October 8, 2010 by and among Unitil Corporation and Bank of America, N.A.	Exhibit 10.5 to Form 8-K dated October 8, 2010
10.18	Credit Agreement between Unitil Corporation and Royal Bank of Canada dated December 1, 2008.	Exhibit 10.2 to Form 8-K dated November 26, 2008
10.19	Transition Services Agreement between Unitil Corporation and NiSource, Inc. dated December 1, 2008.	Exhibit 10.3 to Form 8-K dated November 26, 2008
10.20	Parent Guaranty of Unitil Corporation for the Granite State 7.15% Senior Notes due December 15, 2018.	Exhibit 10.1 to Form 8-K dated December 15, 2008
10.21	Unitil Corporation—Compensation of Directors.	Filed herewith
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
16.1	Letter Re: Change in Certifying Accountant	Exhibit 16.1 to Form 8-K dated September 22, 2010
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
23.2	Consent of Independent Registered Public Accounting Firm.	Filed herewith

Exhibit Number	Description of Exhibit	Reference*
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith
99.1	Unitil Corporation Press Release Dated February 3, 2011 Announcing Earnings for the Quarter and Year Ended December 31, 2010.	Filed herewith
101.INS	XBRL Instance Document.	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema Document.	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	Filed herewith
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	Filed herewith
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** In accordance with Item 601(b)(4)(iii)(A) of Federal Securities Regulation S-K, the instrument defining the debt of the Registrant and its subsidiary, described above, has been omitted but will be furnished to the Commission upon request.

*** These exhibits represent a management contract or compensatory plan.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 3, 2011

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board of Directors,
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 3, 2011
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 3, 2011
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	February 3, 2011
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 3, 2011
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 3, 2011
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 3, 2011
/s/ WILLIAM D. ADAMS **William D. Adams**	Director	February 3, 2011
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 3, 2011
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 3, 2011
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 3, 2011
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 3, 2011
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 3, 2011
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	February 3, 2011

EXHIBIT INDEX

Exhibit No.	Description
10.21	Unitil Corporation—Compensation of Directors
11.1	Computation in Support of Earnings per Share
12.1	Computation in Support of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Registrant
23.1	Consent of Independent Registered Public Accounting Firm
23.2	Consent of Independent Registered Public Accounting Firm
31.1-31.3	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Unitil Corporation Press Release Dated February 3, 2011 Announcing Earnings for the Quarter and Year Ended December 31, 2010.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2010	2009	2008
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$ 9,616**	$10,049	$9,735
Less: Dividend Requirements on Preferred Stock	**132**	134	135
Net Income Applicable to Common Stock	**$ 9,484**	$ 9,915	$9,600
Average Number of Common Shares Outstanding—Basic	**10,823**	9,647	5,830
Dilutive Effect of Stock Options and Restricted Stock	**1**	—	—
Average Number of Common Shares Outstanding—Diluted	**10,824**	9,647	5,830
Earnings Per Share—Basic	**$ 0.88**	$ 1.03	$ 1.65
Earnings Per Share—Diluted	**$ 0.88**	$ 1.03	$ 1.65

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2010	2009	2008	2007	2006
(000's, except ratios)					
Earnings:					
Net Income, per Consolidated Statement of Earnings	**$ 9,616**	$10,049	$ 9,735	$ 8,746	$ 8,033
Federal and State Income Taxes included in Operations	**4,464**	5,220	4,450	4,482	4,266
Interest on Long-Term Debt	**19,664**	17,961	11,795	10,919	9,404
Amortization of Debt Discount Expense	**307**	233	151	136	112
Other Interest	**2,015**	2,474	1,156	1,949	1,675
Total	**$36,066**	$35,937	$27,287	$26,232	$23,490
Fixed Charges:					
Interest of Long-Term Debt	**$19,664**	$17,961	$11,795	$10,919	$ 9,404
Amortization of Debt Discount Expense	**307**	233	151	136	112
Other Interest	**2,015**	2,474	1,156	1,949	1,675
Pre-tax Preferred Stock Dividend Requirements	**194**	208	199	213	208
Total	**$22,180**	$20,876	$13,301	$13,217	$11,399
Ratio of Earnings to Fixed Charges	**1.63**	1.72	2.05	1.98	2.06

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has eight wholly-owned subsidiaries, seven of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Northern Utilities, Inc., Granite State Gas Transmission, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The eighth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements of Unitil Corporation and subsidiaries on Form S-3 (File No. 333-168394 effective July 29, 2010), Form S-3 (File No. 333-158537 effective April 29, 2009), Form S-3 (File No. 333-152823 effective December 5, 2008), Form S-8 (File No. 333-114978 effective April 29, 2004) and on Form S-8 (File No. 333-42266 effective July 26, 2000) of our report dated February 3, 2011, relating to the consolidated financial statements of Unitil Corporation and subsidiaries (the Company) as of December 31, 2010 and the year ending December 31, 2010 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, appearing in the Annual Report of the Company on Form 10-K for the year ended December 31, 2010.

/s/ McGladrey & Pullen, LLP
Boston, Massachusetts
February 3, 2011

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements of Unitil Corporation and subsidiaries on Form S-3 (File No. 333-168394 effective July 29, 2010), Form S-3 (File No. 333-158537 effective April 29, 2009), Form S-3 (File No. 333-152823 effective December 5, 2008), Form S-8 (File No. 333-114978 effective April 29, 2004), and on Form S-8 (File No. 333-42266 effective July 26, 2000) of our report dated February 10, 2010, relating to the consolidated financial statements of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and the two years ending December 31, 2009, appearing in the Annual Report of the Company on Form 10-K for the year ended December 31, 2010.

/s/ Caturano and Company, Inc.
Boston, Massachusetts
February 3, 2011

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 3, 2011

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 3, 2011

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 3, 2011

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 3, 2011
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 3, 2011
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 3, 2011

[THIS PAGE INTENTIONALLY LEFT BLANK]

INFORMATION

2011 Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at the office of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 21, 2011, at 10:30 a.m.

Transfer Agent

The Company's Transfer Agent, Computershare Trust Company, N.A. ("Computershare"), is responsible for all shareholder records, including stock transfer; and the distribution of dividends, tax documents and annual meeting materials to registered holders. Shareholder requests regarding these and other matters can be addressed by corresponding directly with Computershare at:

Mail: PO Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
Website: www.computershare.com/investor

For information about the Company and your investment, you may also call the Company directly, toll-free, at: 800-999-6501 and ask for the Shareholder Representative; or visit the Investor Relations page at www.unitil.com; or contact us at InvestorRelations@unitil.com.

PROGRAMS AND PLANS

Dividend Reinvestment Plan

A Dividend Reinvestment and Stock Purchase Plan is available to registered holders of the Company's Common Stock. This Plan provides shareholders with an economical means to increase their investment in the Company each quarter by reinvesting their dividends without broker fees. For additional information or enrollment, please contact the Company or Computershare.

Dividend Direct Deposit

Dividend Direct Deposit Service is available without charge to shareholders of record of the Company's Common Stock. For further information or enrollment in this service, please contact the Company or Computershare.

Direct Registration

The Company's Common Stock is eligible for Direct Registration or "DRS", which is available without charge to shareholders of record. DRS is a service within the securities industry that allows shares to be held and tracked electronically, without having to retain a physical stock certificate. For additional information, please contact Computershare at:

Mail: PO Box 43084
Providence, RI 02940-3084
Telephone: 800-935-9330
Website: www.computershare.com/investor

Unitil Corporation • 6 Liberty Lane West • Hampton, NH 03842-1720

MIX
Paper from responsible sources
FSC® C101537
www.fsc.org

The paper used in the production of this booklet is FSC® Certified and is harvested under environmentally responsible conditions. It is printed using vegetable-based inks.

002CS-I0944

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.03) Federal income tax reconciliation for the test year.

Response:

Please see the federal income tax reconciliation for the test year for Unitil Corporation on page 71 of Unitil Corporation's Annual Report to Shareholders, which is included in Item 25.02 of these Supplementary Filing Requirements.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.04) Detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income.

Response:

Not applicable to Unitil Corporation.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.05) Detailed list of charitable contributions charged in the test year showing donee and the amount.

Response:

See Response (26.05)

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.06) List of advertising charged in the test year above the line showing expenditure by media and by subject matter.

Response:

See Response (26.06)

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.07) The utility's most recent cost of service study.

Response:

Not applicable to Unitil Corporation.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.08) The utility's most recent construction budget.

Response:

Unitil Corporation does not have a Construction Budget.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.09) The utility's chart of accounts, if different from the uniform system of accounts established by the commission as part of Puc 300, Puc 400, Puc 500, Puc 600 and Puc 700.

Response:

Please see Response 1604.01 (a) (9).

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

Tab Number	Request
49	(26) As to a subsidiary as referred to in (25) above, in lieu of duplicate copies of documentation required by Puc 1604.01(a)(5), (6), (11), (16), and (17), a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service (questions repeated below);
49	(26.05) Detailed list of charitable contributions charged in the test year showing donee and the amount according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all contributions shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all contributions of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all contributions of $2,500 and more shall be reported; d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all contributions of $5,000 and more shall be reported; and e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution;
49	(26.06) List of advertising charged in the test year above the line showing expenditure by media and by subject matter according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all expenditures shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all expenditures of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all expenditures of $2,500 and more shall be reported; and d. If the utility's annual gross reveneus are $100,000,000 or are in excess of $100,000,000, all expenditures of $5,000 and more shall be reported;
49	(26.11) Detailed list of all membership fees, dues, donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all membership fees, dues and donations shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all membership fees, dues and donations of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all membership fees, dues and donations of $2,500 and more shall be reported; and d. If the utility's annual gross reveneus are $100,000,000 or are in excess of $100,000,000, all membership fees, dues and donations of $5,000 and more shall be reported;

NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

Pursuant to PUC 1604.01 (a)

TABLE OF CONTENTS

In accordance with the New Hampshire code of Administrative Rules PUC 1604.01 (a), Northern Utilities, Inc. ("NU") has prepared responses to the following requests as provided herein:

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.10) The utility's Securities and Exchange Commission 10K forms and 10Q forms, for the most recent 2 years.

Response:

Please see the attached for copies of Unitil Corporation's Form 10-K's and Form 10-Q's as follows:

- Form 10-K's for the years ended:
  - December 31, 2008
  - December 31, 2009

- Form 10-Q's for the quarters ended:
  - March 31, 2008
  - June 30, 2008
  - September 30, 2008
  - March 31, 2009
  - June 30, 2009
  - September 30, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire **(State or other jurisdiction of incorporation or organization)**	**02-0381573** **(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire **(Address of principal executive offices)**	**03842-1720** **(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Based on the closing price of June 30, 2009, the aggregate market value of common stock held by non-affiliates of the registrant was $219,996,265.

The number of common shares outstanding of the registrant was 10,838,394 as of February 9, 2010.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010 are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2009
Table of Contents

[THIS PAGE INTENTIONALLY LEFT BLANK]

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly owned subsidiaries of Unitil:

Company Name	State and Year of Organization	Principal Business
Unitil Energy Systems, Inc. (Unitil Energy)	NH - 1901	Electric Distribution Utility
Fitchburg Gas and Electric Light Company (Fitchburg)	MA - 1852	Electric & Gas Distribution Utility
Northern Utilities, Inc. (Northern Utilities)	NH - 1979	Natural Gas Distribution Utility
Granite State Gas Transmission, Inc. (Granite State)	NH - 1955	Natural Gas Transmission Pipeline
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-regulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering and Advisory Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territories in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly owned distribution utilities: i) Unitil Energy, which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the city of Concord, New Hampshire, ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts, and iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area. In addition, Unitil is the parent company of Granite State, an interstate natural gas transmission pipeline company that provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory. Together, Unitil's three distribution utilities serve approximately 100,500 electric customers and 70,000 natural gas customers.

Unitil's distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in net utility plant of $449.7 million at December 31, 2009. Unitil's total operating revenue was $367.0 million in 2009. Substantially all of Unitil's operating revenue is derived from regulated utility operations.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are indirect subsidiaries that are wholly owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

OPERATIONS

Gas Operations

Unitil's Gas Operations include gas distribution utility operations and gas transportation pipeline company operations, discussed below. Revenue from Unitil's gas operations was $152.8 million for 2009, which represent about 42% of Unitil's total operating revenue. In 2008, the Company significantly expanded its gas operations by acquiring Northern Utilities and Granite State on December 1, 2008.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, originally founded as Portland Gas Light Company in 1849, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate natural gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the Acquisitions). Bay State is a wholly owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt (see "Liquidity, Commitments and Capital Requirements" section in Part II, Item 7 below). The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features (See Note 6 to the accompanying Consolidated Financial Statements for additional information on these settlement agreements).

Gas Distribution Utility Operations

Unitil's natural gas utility operations are conducted through two of the Company's distribution utilities, Northern Utilities and Fitchburg. The primary business of Unitil's natural gas utility operations is the local distribution of natural gas to customers in its service territory in New Hampshire, Massachusetts and Maine. As a result of a restructuring of the gas utility industry in New Hampshire, Massachusetts and Maine, Fitchburg's residential and commercial and industrial (C&I) customers and Northern Utilities' C&I customers have the opportunity to purchase their natural gas supplies from third-party energy supply vendors. Most customers, however, continue to purchase such supplies through Northern Utilities and Fitchburg under regulated rates and tariffs. Northern Utilities and Fitchburg purchase natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis through reconciling rate mechanisms that are periodically adjusted.

Natural gas is supplied and distributed by Northern Utilities to approximately 54,800 customers in 44 New Hampshire and southern Maine communities, from Plaistow, New Hampshire in the south to the city of Portland, Maine and then extending to Lewiston-Auburn, Maine in the north. Northern Utilities has a diversified customer base both in Maine and New Hampshire. Commercial businesses include healthcare, education, government and retail. Northern Utilities' industrial base includes manufacturers in the industries of auto, housing, rubber, printing, textile, pharmaceutical, electronics, wires and food production as well as a military installation. Northern Utilities 2009 gas operating revenue was $113.9 million, of which approximately 37.0% was derived from residential firm sales and 63.0% from C&I firm sales.

Natural gas is supplied and distributed by Fitchburg to approximately 15,200 customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. Fitchburg's 2009 gas operating revenue was $34.8 million, of which approximately 54.0% was derived from residential firm sales and 46.0% from commercial/industrial firm sales.

Gas Transmission Pipeline Company Operations

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State

provides Northern Utilities with interconnection to major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State had operating revenue of $4.1 million for 2009. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Electric Distribution Utility Operations

Unitil's electric utility operations are conducted through two of the Company's distribution utilities, Unitil Energy and Fitchburg. Revenue from Unitil's electric utility operations was $209.9 million for 2009, which represent about 57% of Unitil's total operating revenue.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its service territory in New Hampshire and Massachusetts. As a result of the implementation of choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The distribution utilities continue to deliver that supply of electricity over their distribution systems. Both Unitil Energy and Fitchburg supply electricity to those customers who do not obtain their supply from third-party suppliers, with the approved costs associated with electricity supplied by the distribution utilities being recovered on a pass-through basis under periodically-adjusted rates.

Unitil Energy distributes electricity to approximately 72,600 customers in New Hampshire in the capital city of Concord as well as parts of 12 surrounding towns and all or part of 18 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. Unitil Energy's service territory consists of approximately 408 square miles. In addition, Unitil Energy's service territory encompasses retail trading and recreation centers for the central and southeastern parts and includes the Hampton Beach recreational area. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics, healthcare and education. Unitil Energy's 2009 electric operating revenue was $146.4 million, of which approximately 51.0% was derived from residential sales and 49.0% from commercial/industrial sales.

Fitchburg is engaged in the distribution of both electricity and natural gas in the greater Fitchburg area of northcentral Massachusetts. Fitchburg's service territory encompasses approximately 170 square miles. Electricity is supplied and distributed by Fitchburg to approximately 27,900 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries and education. Fitchburg's 2009 electric operating revenue was $63.5 million, of which approximately 54.0% was derived from residential sales and 46.0% from commercial/industrial sales.

Seasonality

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company's results will reflect the seasonal nature of the natural gas distribution business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours. Unitil Energy, Fitchburg and Northern Utilities are not dependent on a single customer or a few customers for their electric and natural gas sales.

Non-regulated and Other Non-Utility Operations

Unitil's non-regulated operations are conducted through Usource, a subsidiary of Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's non-regulated operations was $4.3 million in 2009.

The results of Unitil's other non-utility subsidiaries, Unitil Service and Unitil Realty, and the holding company are included in the Company's consolidated results of operations. The results of these non-utility operations are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and are reported, after intercompany eliminations, in Other segment income (for segment information, see Part II, Item 8, Note 10 herein).

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 with regard to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, with regard to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and Maine Public Utilities Commission (MPUC). Granite State, Unitil's interstate natural gas transmission pipeline, is subject to regulation by the FERC with regard to their rates and operations. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party energy supply vendors. Most customers, however, continue to purchase such supplies through the distribution utilities under regulated energy rates and tariffs. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual approved costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

On December 11 and 12, 2008, a severe ice storm struck the New England region (December 2008 Ice Storm), causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers.

The Company has received regulatory approval to defer storm restoration costs and has accrued and deferred approximately $14.6 million of costs, including carrying charges, incurred for the repair of its electric system damaged during the ice storm so that it may seek recovery of these costs in its next base rate cases. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, there may be a significant impact on the Company's results of operations in future periods.

Also see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Rates and Regulation.

NATURAL GAS SUPPLY

With the purchase of Northern Utilities on December 1, 2008, Unitil now manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and C&I customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, although most of Fitchburg's customers continue to purchase such supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply at regulated rates from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

In the fourth quarter of 2009, the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus carrying charges, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. Fitchburg has appealed this order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of LNG or LPG, to truck supplies to each storage facility within Northern Utilities' service territory.

Northern has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

ELECTRIC POWER SUPPLY

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third party energy suppliers. As of December 2009, 99 or 67% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 79% of Unitil's largest Massachusetts customers, representing 35% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential and small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

Prior to May 1, 2003, Unitil Energy purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, Unitil Energy and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to Unitil Energy ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, Unitil Energy continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. In connection with the restructuring of the electric industry, Unitil Power and Fitchburg divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts.

Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

ENVIRONMENTAL MATTERS

Unitil's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed. Also, see Note 6 to the accompanying consolidated financial statements.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800's through the mid 1900's. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Also, see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES

As of December 31, 2009, the Company and its subsidiaries had 431 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2009, 156 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two agreements expire on May 31, 2010, one agreement expires on June 5, 2010 and one agreement expires on March 31, 2012. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is *www.unitil.com*. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the New York Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 10, 2010:

Name	Age	Position
Robert G. Schoenberger	59	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	50	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	47	Senior Vice President and Chief Operating Officer
Laurence M. Brock	56	Controller and Chief Accounting Officer
Todd R. Black	45	Senior Vice President, External Affairs and Customer Relations, Unitil Service
George R. Gantz	58	Senior Vice President, Distributed Energy Resources, Unitil Service
George E. Long, Jr.	53	Vice President, Administration, Unitil Service
Sandra L. Whitney	46	Corporate Secretary
William D. Adams	62	Director
Dr. Robert V. Antonucci	64	Director
David P. Brownell	66	Director
Michael J. Dalton	69	Director
Albert H. Elfner, III	65	Director
Edward F. Godfrey	60	Director
Michael B. Green	60	Director
Eben S. Moulton	63	Director
M. Brian O'Shaughnessy	66	Director
Dr. Sarah P. Voll	67	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board of Directors and Chief Executive Officer since 1997, as well as President since 2003. Prior to his employment with Unitil, Mr. Schoenberger was president and chief operating officer of the New York Power Authority (a state-owned utility) from 1993 until 1997. Mr. Schoenberger has also served as a director of SatCon Technology Corporation, Boston, Massachusetts (a company engaged in the development and manufacture of power electronics and control systems) since 2007. Mr. Schoenberger formerly served as chairman and trustee of Exeter Health Resources, Exeter, New Hampshire, from 1998 until 2009, and as a director of the Greater Seacoast (New Hampshire) United Way from 1998 until 2004, the New England Gas Association from 1999 until 2002 and the Southwest Power Pool from 2003 until 2005.

Mark H. Collin has been Unitil's Senior Vice President and Chief Financial Officer since February 2003. Mr. Collin has also served as Treasurer since 1998. Mr. Collin joined Unitil in 1988, and served as Vice President of Finance from 1995 until 2003.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President and Chief Operating Officer since June 2005. Mr. Meissner served as Senior Vice President, Operations, from February 2003 until June 2005. Mr. Meissner joined Unitil in 1994 and served as Director of Engineering from 1998 until 2003.

George R. Gantz has been Unitil's Senior Vice President, Distributed Energy Resources, Unitil Service, since September 2009. Mr. Gantz joined Unitil in 1983 and served as Senior Vice President, Communication and Regulation from 1994 until 2003, and Senior Vice President, Customer Services and Communications from 2003 until 2009.

Todd R. Black has been Unitil's Senior Vice President, External Affairs and Customer Relations, Unitil Service, since September 2009. Mr. Black joined Unitil in 1998 and served as Vice President, Sales and Marketing, for Usource from 1998 until 2003, and President of Usource from 2003 until 2009.

Laurence M. Brock has been Unitil's Controller and Chief Accounting Officer since June 2005. Mr. Brock joined Unitil in 1995 as Vice President and Controller, and is a certified public accountant in the state of New Hampshire.

George E. Long, Jr. has been Unitil's Vice President, Administration, Unitil Service, since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources, from 1998 until 2003.

Sandra L. Whitney has been Unitil's Corporate Secretary and secretary of our Board of Directors since February 2003. Ms. Whitney joined Unitil in 1990 and also serves as the Corporate Secretary of Unitil's subsidiary companies.

William D. Adams has been a member of Unitil's Board of Directors since 2009. Mr. Adams has been the president of Colby College in Waterville, Maine, since 2000. Mr. Adams also serves on the board of trustees of Colby College. Mr. Adams also served as president of Bucknell University (Bucknell) in Pennsylvania from 1995 until 2000. Prior to leading Bucknell, he served as vice president and secretary of Wesleyan University in Connecticut. Mr. Adams also served as coordinator of the Great Works in Western Culture program at Stanford University and taught political philosophy at the University of North Carolina at Chapel Hill and Santa Clara University. Mr. Adams has served on the board of directors of Wittenburg University since 2007, Maine General Health since 2002, and Maine Public Broadcasting Corporation since 2002.

Dr. Robert V. Antonucci has been a member of Unitil's Board of Directors since 2004. Dr. Antonucci has been the president of Fitchburg State College (FSC) in Fitchburg, Massachusetts, since 2003. Prior to his employment with FSC, Dr. Antonucci was president of the School Group of Riverdeep, Inc., San Francisco, California, from 2001 until 2003 and president and chief executive officer of Harcourt Learning Direct and Harcourt Online College, Chestnut Hill, Massachusetts from 1998 until 2001. Dr. Antonucci also served as the commissioner of education for the Commonwealth of Massachusetts from 1992 until 1998. In addition, Dr. Antonucci has served as a trustee of Eastern Bank since 1988. Dr. Antonucci also serves and a director of the North Central Massachusetts Chamber of Commerce and a director of the North Central Massachusetts United Way.

David P. Brownell has been a member of Unitil's Board of Directors since 2001. Mr. Brownell has been a retired senior vice president of Tyco International Ltd. (Tyco) (a diversified global manufacturing and service company), Portsmouth, New Hampshire, since 2003. Mr. Brownell had been with Tyco since 1984. Mr. Brownell was also interim president of the University of New Hampshire (UNH) Foundation, former vice chairman of the board of UNH Foundation, former volunteer board president of the United Way of the Greater Seacoast, and a former board member of the New Hampshire Junior Achievement Advisory Council.

Michael J. Dalton has been a member of Unitil's Board of Directors since 1984. Mr. Dalton has been the retired president and chief operating officer of Unitil since 2003. Mr. Dalton has been a member of the Industrial Advisory Council of the University of New Hampshire College of Engineering and Physical Sciences since 2003, and vice president since 2009. Mr. Dalton was a director of the New England Gas Association from 2002 until 2003, the Electric Council of New England, the UNH Foundation, the University of New Hampshire Alumni Association, and the University of New Hampshire President's Council. In addition, Mr. Dalton serves as a mentor with the University of New Hampshire Pathways Mentorship Program.

Albert H. Elfner, III has been a member of Unitil's Board of Directors since 1999. Mr. Elfner was the chairman of Evergreen Investment Management Company, Boston, Massachusetts, from 1994 until 1999 and its chief executive officer from 1995 until 1999. Mr. Elfner is also a director of NGM Insurance Company (NGM), Jacksonville, Florida, as well as a member of the NGM finance committee, and as a director of Emerson Ecologics, LLC (distributor of natural health care products to health care professionals), and as a trustee of MDT Advisors (a quantitative investment management firm), Boston, Massachusetts.

Edward F. Godfrey has been a member of Unitil's Board of Directors since 2002. Mr. Godfrey was the executive vice president and chief operating officer of Keystone Investments, Incorporated (Keystone), Boston, Massachusetts, from 1997 until 1998. Mr. Godfrey was senior vice president, chief financial officer and treasurer of Keystone from 1988 until 1996. Mr. Godfrey is also a director of VehiCare, LLC, Charlotte, North Carolina, since 2006.

Michael B. Green has been a member of Unitil's Board of Directors since 2001. Mr. Green has been the president and chief executive officer of Capital Region Health Care and Concord Hospital, Concord, New Hampshire, since 1992. Mr. Green is also a member of the adjunct faculty, Dartmouth Medical School, Dartmouth College, Hanover, New Hampshire. In addition, Mr. Green currently serves on the board of the Foundation for Healthy Communities, is a director of the New Hampshire Hospital Association, a director of New Hampshire Business Council for the Arts, and a director of Merrimack County Savings Bank including membership on the bank's investment and audit committees.

Eben S. Moulton has been a member of Unitil's Board of Directors since 2000. Mr. Moulton has been the managing partner of Seacoast Capital Corporation, Danvers, Massachusetts, (a private investment company) since 1995. Mr. Moulton is also a director of IEC Electronics (provider of electronic manufacturing services to advanced technology companies), Newark, New York, a director of six private companies, and a trustee of Colorado College, Colorado Springs, Colorado.

M. Brian O'Shaughnessy has been a member of Unitil's Board of Directors since 1998. Mr. O'Shaughnessy has been the chairman of the board of Revere Copper Products, Inc. (Revere), Rome, New York, since 1988. Mr. O'Shaughnessy also served as chief executive officer and president of Revere from 1988 until 2007. Mr. O'Shaughnessy also serves on the Board of Directors and as the chief co-chair of the Coalition for a Prosperous America, three copper industry trade associations, three manufacturing associations in New York State regarding energy-related issues, and the Economic Development Growth Enterprise of Mohawk Valley.

Dr. Sarah P. Voll has been a member of Unitil's Board of Directors since 2003. Dr. Voll has been a retired vice president, National Economic Research Associates, Inc. (NERA), Washington, District of Columbia, a firm of consulting economists specializing in industrial and financial economics, since 2007, but currently serves as a special consultant to NERA. Dr. Voll had been with NERA in the position of vice president since 1999, and in the position of senior consultant from 1996 until 1999. Prior to her employment with NERA, Dr. Voll was a staff member at the NHPUC from 1980 until 1996.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 15, 2010, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of common stock, administration of the Dividend Reinvestment and Stock Purchase Plan, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Computershare
P.O. Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

Investor Relations

For information about the Company, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at *www.unitil.com*; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available to Holders of Record

If a shareholder's shares of common stock are registered directly in the shareholder's name with the Company's transfer agent, the shareholder is considered a holder of record of the shares. The following services and programs are available to shareholders of record:

- Internet Account Access is available at *www.computershare.com*.
- Dividend Reinvestment and Stock Purchase Plan:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Direct Registration:

  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

Risks related to the regulation of the Company's business could impact the rates it is able to charge, its costs and its profitability.

The Company is subject to comprehensive regulation by federal and state regulatory authorities, which significantly influences the Company's operating environment and its ability to recover costs from its customers. In particular, the Company is regulated by the FERC and state regulatory authorities with jurisdiction over public utilities, including the NHPUC, MDPU and MPUC. These authorities regulate many aspects of the Company's operations, including, but not limited to, construction and maintenance of facilities, operations, safety, issuance of securities, accounting matters, transactions between affiliates, the rates that the Company can charge customers and the rate of return that it is allowed to realize. The Company's ability to obtain rate adjustments to maintain its current rate of return depends upon regulatory action under applicable statutes, rules and regulations, and the Company cannot assure you that it will be able to obtain rate adjustments or continue receiving its current authorized rates of return. These regulatory authorities are also empowered to impose financial penalties and other sanctions on the Company if it is found to have violated statutes and regulations governing its utility operations. The Company is unable to predict the impact on its operating results from the regulatory activities of any of these agencies. Although the Company has attempted to actively manage the rate making process and has had recent success in obtaining rate adjustments, it can offer no assurances as to future success in the rate making process. Despite the Company's requests, these regulatory commissions have authority under applicable statutes, rules and regulations to leave the Company's rates unchanged, grant increases or order decreases in such rates.

The regulators also have authority with respect to the recovery of the Company's electricity and natural gas supply costs incurred by Unitil Energy, Fitchburg, and Northern Utilities. In the event that the Company is unable to recover a significant amount of these costs or recovery of these costs were to be significantly delayed, the Company's operating results could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have an adverse effect on the Company's operating results.

In the fourth quarter of 2009, the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus carrying charges, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

The Company has deferred certain costs associated with the December 2008 Ice Storm for future recovery in rates.

On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers.

The Company has received regulatory approvals to defer storm restoration costs and has accrued and deferred approximately $14.6 million of costs, including carrying charges, for the repair of its electric system damaged during the December 2008 Ice Storm so that it may seek recovery of these costs in its next base rate cases. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, there may be a significant impact on the Company's results of operations in future periods.

As a result of electric industry restructuring, the Company has a significant amount of certain stranded electric generation and generation related supply costs.

The stranded costs resulting from the implementation of electric industry restructuring mandated by the states of New Hampshire and Massachusetts are recovered by the Company on a pass-through basis through periodically reconciled rates. Any unrecovered balance of purchased power or stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

The Company's power supply-related regulatory assets due to the electric industry restructuring in New Hampshire and Massachusetts for which regulatory approval has been obtained for recovery were approximately $25.6 million for Fitchburg and $9.1 million for Unitil Energy as of December 31, 2009, including $8.4 million and $4.6 million for Fitchburg and Unitil Energy, respectively, recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Additionally, the Company's other restructuring-related regulatory assets for which regulatory approval has been obtained for recovery were approximately $28.3 million in the aggregate as of December 31, 2009, including $4.7 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet.

Substantially all of Fitchburg's stranded costs relate to owned generation assets and purchase power agreements divested by Fitchburg under a long-term contract buy-out agreement. Unitil Energy's stranded costs are attributable to the long-term power purchase agreements divested by Unitil Power under long-term contract buyout agreements. Because Fitchburg and Unitil Power remain ultimately responsible for purchase power payments underlying these long-term buyout agreements, Fitchburg and Unitil Power could incur additional stranded costs were they required to resell such divested entitlements prior to the end of their term for amounts less than the amounts agreed to under the existing long-term buyout agreements. The Company expects that any such additional stranded costs would be recovered from its customers, although such recovery would require approval from the MDPU or NHPUC, the receipt of which cannot be assured.

The Company's electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may negatively impact the Company's customers and correspondingly its operating results and financial condition.

The Company's business is influenced by the economic activity within its service territory. The level of economic growth in the Company's electric and natural gas distribution service territory directly affects the potential for future growth in the Company's business. As a result, adverse changes in the economy may have negative effects on the Company's revenues, operating results and financial condition.

The Company may not be able to obtain financing or obtain financing on acceptable terms, which could have an adverse affect on the Company's operating results and financial condition.

The Company requires capital to fund utility plant additions, working capital and other utility expenditures. While the capital necessary to meet these requirements is derived primarily from internally-generated funds, the Company initially supplements internally generated funds through short-term debt under its current credit facility, as needed, and periodically replaces portions of its short-term debt with permanent financing sources such as long-term debt or equity. General economic conditions and the Company's operating and financial performance could negatively affect the Company's ability to obtain financing and the terms of such financing. In addition, the Company may be unable to obtain debt financing under its current credit facility because its lending counterparties may be unwilling or unable to meet their funding obligations. In each case, this could hinder or prevent the Company from meeting its current and future capital needs, which could correspondingly have an adverse affect on the Company's operating results and financial condition. In addition, the material terms of the Company's existing indebtedness restricts its ability to incur any material amount of additional indebtedness, which could negatively impact its operating results and financial condition. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

Declines in the valuation of capital markets could require the Company to make substantial cash contributions to cover its pension obligations, which could negatively impact its financial condition.

On August 17, 2006, the Pension Protection Act of 2006 (the PPA) was signed into law. Included in the PPA are new minimum funding rules which came into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period provided pursuant to the PPA. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 – 2010 plan years.

The Company made cash contributions of $4.2 million, $2.8 million and $2.8 million to its pension plan in 2009, 2008 and 2007, respectively, which exceeded minimum funding requirements. Recent and future declines in the valuation of capital markets could require the Company to make cash contributions to its pension plans substantially in excess of its cash contributions in prior years, which could adversely affect its financial condition.

The Financial Accounting Standards Board (FASB) guidance on accounting for pension and other post retirement benefit obligations requires companies to record on their balance sheets the funded status of their retirement benefit obligations (RBO). The Company has recognized a liability for the projected RBO of its plans and a corresponding regulatory asset, to recognize the future collection of these obligations in electric and gas rates. In the event that the Company is unable to recover these costs or recovery of these costs were to be significantly delayed, the Company's operating results could be materially adversely affected. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 9 to the accompanying Consolidated Financial Statements.

Increases in interest rates could have a negative impact on the Company's financial condition and the Company may need to use a significant portion of its cash flow to repay its outstanding indebtedness.

The Company and its utility subsidiaries have ongoing capital expenditure and cash funding requirements that they frequently fund by issuing short-term debt and long-term debt.

Short-term debt borrowings are typically at variable rates of interest. Therefore, changes in short-term interest rates will increase or decrease the Company's interest expense associated with short-term borrowings. Increases in interest rates generally will increase the Company's borrowing costs with respect to short-term debt and could adversely affect its financial condition or results of operations. As of December 31, 2009, the Company had approximately $64.5 million outstanding under its revolving credit facility.

Long-term debt borrowings are typically at fixed rates of interest. Therefore, changes in interest rates do not affect interest expense associated with presently outstanding fixed rate long-term debt securities. However, changes in interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities that are issued. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

The Company may need to use a significant portion of its cash flow to repay its short-term debt and long-term debt, which would limit the amount of cash it has available for working capital, capital expenditures and other general corporate purposes and could negatively affect its liquidity, financial condition and results of operations.

The Company's and its subsidiaries' indebtedness contains covenants that could restrict the Company's business operations.

See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

Weather conditions may cause the Company's sales to vary from year to year.

Sales by the Company's distribution utilities vary from year to year, depending on weather conditions. The Company estimates that approximately 50% of its annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of natural gas sold by the Company in any year, particularly during the winter heating season. The Company's electric sales are generally less sensitive to weather than its natural gas sales, but may also be affected by weather conditions in both the winter and summer seasons. The highest usage of electricity typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours.

The Company's results of operations reflect this seasonal nature. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by Northern Utilities, which was acquired by the Company on December 1, 2008. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Unitil is a holding company and has no operating income of its own. The Company's ability to pay dividends on its common stock is dependent on dividends received from its subsidiaries and on factors directly affecting Unitil, the parent corporation. The Company cannot assure you that its current annual dividend will be paid in the future.

Unitil is a public utility holding company and it does not have any operating income of its own. Consequently, the Company's ability to pay dividends on its common stock is dependent on dividends and other payments received from its subsidiaries, principally Unitil Energy, Fitchburg, Northern Utilities and Granite State. The ability of the Company's subsidiaries to pay dividends or make distributions to Unitil will depend on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of our subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by the Company's subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of Unitil Energy, Fitchburg, Northern Utilities and Granite State and that may be contained in future debt agreements of the Company's subsidiaries, if any; and
- limitations that may be imposed by New Hampshire, Massachusetts and Maine state regulatory agencies.

In addition, the Company may incur indebtedness in the future. Before the Company can pay dividends on its common stock, it has to satisfy its debt obligations and comply with any statutory or contractual limitations.

The Company's current annual dividend is $1.38 per share of common stock, payable quarterly. However, the Company's Board of Directors reviews Unitil's dividend policy periodically in light of the factors referred to above, and the Company cannot assure the amount of dividends, if any, that may be paid in the future.

Transporting and storing natural gas and supplemental gas supplies, as well as electricity, involves numerous risks that may result in accidents and other operating risks and costs.

Inherent in the Company's electric and natural gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions, electrocutions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, and impairment of the Company's operations and substantial losses to Unitil. In accordance with customary industry practice, the Company maintains insurance against some, but not all, of these risks and losses. The location of pipelines, storage facilities and electric distribution equipment near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect the Company's financial position and results of operations.

The Company's business is subject to environmental regulation in all jurisdictions in which it operates and its costs of compliance are significant. Any changes in existing environmental regulation and the incurrence of environmental liabilities could negatively affect the Company's results of operations and financial condition.

The Company's utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources, and the health and safety of the Company's employees. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; imposition of remedial requirements; and even issuance of injunctions to ensure future compliance. Liability under certain environmental laws is strict, joint and several in nature. Although the Company believes it is in general compliance with all applicable environmental and safety laws and regulations, there can be no assurance that significant costs and liabilities will not be incurred in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, could result in increased environmental compliance costs.

Catastrophic events could have a material adverse effect on the Company's financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could have a material adverse effect on the Company since they could inhibit its ability to continue providing electric and/or natural gas distribution services to its customers for an extended period, which is the principal source of the Company's operating income.

The Company's business could be adversely affected if it is unable to retain its existing customers or attract new customers.

The success of the Company's business depends, in part, on its ability to maintain and increase its customer base. The Company's failure to maintain or attract customers could have a material adverse effect on its business, financial condition and operating results.

The Company cannot guarantee customers' future performance under multi-year energy brokering contracts.

The Company's non-regulated energy brokering business provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenues from this business are primarily derived from brokering fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts. The Company cannot guarantee customers' future performance under multi-year energy brokering contracts.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2009, Unitil owned, through its distribution utilities, three utility operation centers, approximately 2,177 pole miles of local transmission and distribution overhead electric lines and 596 conduit bank miles of underground electric distribution lines, along with 48 electric substations, including three mobile electric substations. Our natural gas operations property includes two LPG plants, two LNG plants and 1,219 miles of underground gas mains. In addition, our real estate subsidiary, Unitil Realty, owns our corporate headquarters building and the 12 acres of land on which it is located.

Unitil Energy owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. Unitil Energy's 29 electric distribution substations, including one 5,000 kilovolt ampere and one 10,500 kilovolt ampere kVA mobile substation, constitute 219,037 kVA of capacity, which excludes capacity of spare transformers, for the transformation of electric power from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by Unitil Energy or land occupied by Unitil Energy pursuant to perpetual easements.

Unitil Energy has a total of approximately 1,617 pole miles of local transmission and distribution overhead electric lines and a total of 416 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Unitil Energy without objection by the owners. In the case of certain distribution lines, Unitil Energy owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

The physical utility properties of Unitil Energy, with certain exceptions, and its franchises are subject to its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of Unitil Energy are outstanding.

Fitchburg's electric properties consist principally of 560 pole miles of local transmission and distribution overhead electric lines, 180 conduit bank miles of underground electric distribution lines and 19 transmission and distribution stations (including two mobile electric substations). The capacity of these substations totals 443,150 kVA, which excludes capacity of spare transformers.

Fitchburg owns a LPG plant and a LNG plant, both of which are located on land owned by Fitchburg. Fitchburg also has 263 miles of underground steel, cast iron and plastic gas mains.

Fitchburg's electric substations, with minor exceptions, are located on land owned by Fitchburg or occupied by Fitchburg pursuant to perpetual easements. Fitchburg's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Fitchburg without objection by the owners. Fitchburg leases its distribution operations center located in Fitchburg, Massachusetts.

Northern Utilities' distribution system is comprised of 956 miles of gas mains and 38,692 service pipes. The gas mains are primarily made up of polyethylene plastic (65%), coated and wrapped cathodically protected steel (22%), cast/wrought iron (8%), and unprotected bare and coated steel (5%).

Northern Utilities' New Hampshire division serving 21 communities has 485 miles of distribution gas mains and 19,468 service pipes. Northern Utilities' Maine division serving 23 communities has 471 miles of distribution and 19,224 service pipes. Northern Utilities also owns a liquid propane gas plant on land owned by Northern Utilities.

Granite State is a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline located in Maine and New Hampshire.

The Company believes that its facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the December 2008 Ice Storm. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's common stock is listed on the New York Stock Exchange under the symbol "UTL". As of December 31, 2009, there were 1,644 shareholders of record.

Common Stock Data

Dividends per Common Share	2009	2008
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2009		2008	
Price Range of Common Stock	High/Ask	Low/Bid	High/Ask	Low/Bid
1st Quarter	**$20.75**	**$17.93**	$29.00	$25.75
2nd Quarter	**$22.79**	**$19.05**	$28.60	$26.41
3rd Quarter	**$23.20**	**$20.53**	$27.94	$25.46
4th Quarter	**$23.46**	**$19.55**	$26.60	$19.50

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

Equity Compensation Plan Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
Restricted Stock Plan (1)	—	N/A	62,318
Equity compensation plans not approved by security holders			
1998 Option Plan (2)	63,500	$28.90	—
Total	63,500	$28.90	62,318

NOTES: (also see Note 3 to the accompanying Consolidated Financial Statements)

(1) The Restricted Stock Plan (the Plan) was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006; 9,020 shares of restricted stock were awarded to Plan participants in February 2007; 15,540 shares of restricted stock were awarded to Plan participants in February 2008; 32,260 shares of restricted stock were awarded to Plan participants in February 2009. 12,520 shares of restricted stock were awarded to Plan participants in February 2010.

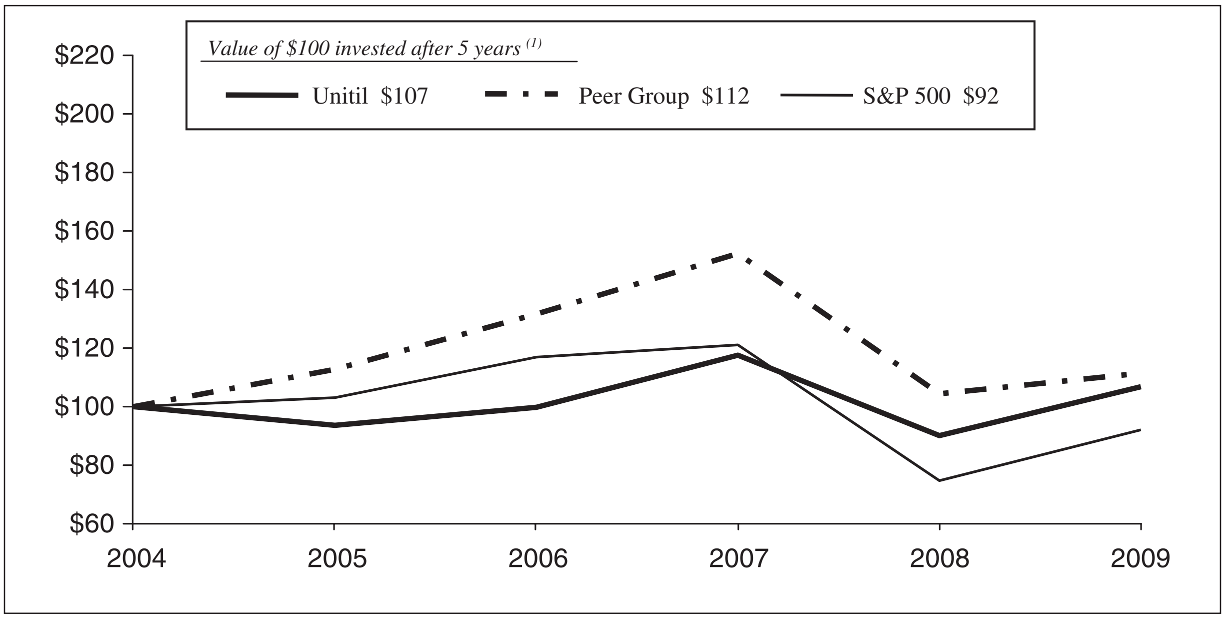
(2) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange (the exchange upon which the Company was then listed) rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of

Directors terminated the 1998 Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the 1998 Option Plan were deregistered with the Securities and Exchange Commission. The 1998 Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the 1998 Option Plan. No further grants of options will be made thereunder.

Stock Performance Graph

The following graph compares Unitil's cumulative stockholder return since December 31, 2004 with the Peer Group index, comprised of the S&P Utility Index, and the S&P 500 index. The graph assumes that the value of the investment in the Company's common stock and each index (including reinvestment of dividends) was $100 on December 31, 2004.

Comparative Five-Year Total Returns



NOTES:

(1) The graph above assumes $100 invested on December 31, 2004, in each category and the reinvestment of all dividends during the five-year period. The Peer Group is comprised of the S&P Utility Index.

Unregistered Sales of Equity Securities and Uses of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2009.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 26, 2009, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases; however, the trading plan will terminate when $83,000 in value of shares have been purchased or, if sooner, on March 26, 2010.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
10/1/09 – 10/31/09	—	—	—
11/1/09 – 11/30/09	—	—	—
12/1/09 – 12/31/09	2,781	$21.57	2,781
Total	2,781	$21.57	2,781

Item 6. Selected Financial Data

For the Years Ended December 31,	2009	2008	2007	2006	2005
(all data in millions except shares, % and per share data) (1)					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 367.0**	$ 288.2	$ 262.9	$ 260.9	$ 232.1
Operating Income	**26.1**	20.5	18.5	15.8	15.5
Other Non-operating Expense (Income)	**0.3**	0.3	0.2	—	0.1
Income Before Interest Expense, net	**25.8**	20.2	18.3	15.8	15.4
Interest Expense, net	**15.8**	10.5	9.6	7.8	6.8
Net Income	**10.0**	9.7	8.7	8.0	8.6
Dividends on Preferred Stock	**0.1**	0.1	0.1	0.1	0.2
Earnings Applicable to Common Shareholders	**$ 9.9**	$ 9.6	$ 8.6	$ 7.9	$ 8.4
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 682.7**	$ 641.4	$ 380.5	$ 353.0	$ 325.0
Total Assets	**$ 725.2**	$ 733.2	$ 474.6	$ 483.4	$ 450.1
Capitalization:					
Common Stock Equity	**$ 193.1**	$ 139.5	$ 100.4	$ 97.8	$ 96.3
Preferred Stock	**2.0**	2.0	2.1	2.1	2.3
Long-Term Debt, less current portion	**248.9**	249.3	159.6	140.0	125.4
Total Capitalization	**$ 444.0**	$ 390.8	$ 262.1	$ 239.9	$ 224.0
Current Portion of Long-Term Debt	**$ 0.4**	$ 0.4	$ 0.4	$ 0.3	$ 0.3
Short-term Debt	**$ 64.5**	$ 74.1	$ 18.8	$ 26.0	$ 18.7
Capital Structure Ratios:					
Common Stock Equity	**43%**	36%	38%	41%	43%
Preferred Stock	**1%**	1%	1%	1%	1%
Long-Term Debt	**56%**	63%	61%	58%	56%
Earnings Per Share Data:					
Earnings Per Average Share	**$ 1.03**	$ 1.65	$ 1.52	$ 1.41	$ 1.51
Common Stock Data:					
Shares of Common Stock—(Average Outstanding, 000's)	**9,647**	5,830	5,672	5,612	5,568
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.83**	$ 17.90	$ 17.50	$ 17.30	$ 17.21
Electric and Gas Sales:					
Electric Distribution Sales (Millions kWh)	**1,618.8**	1,695.9	1,743.0	1,751.5	1,790.4
Firm Natural Gas Distribution Sales (Millions Therms)	**178.7**	47.2	28.4	26.4	24.3

(1) As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

OVERVIEW

Unitil is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy, which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,500 electric customers and 70,000 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite State, a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in Net Utility Plant of $449.7 million at December 31, 2009. Unitil's total revenue was $367.0 million in 2009, which includes revenue to recover the approved cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not affected by changes in the cost of purchased electricity and natural gas. Earnings from Unitil's utility operations are derived from the return on investment in the three distribution utilities and Granite.

Unitil also conducts non-regulated operations principally through Usource, which is wholly-owned by Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Usource's total revenues were $4.3 million in 2009. The Company's other subsidiaries include Unitil Service, which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, and Unitil Realty, which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- The Company's ability to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Recovery of deferred major storm costs;
- Recovery of energy commodity costs;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions that could have an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of our counterparty obligations, including those of our insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A Risk Factors.

ACCOUNTING CODIFICATION

In June 2009, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 168), a replacement of SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles". SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States (U.S. GAAP). SFAS No. 168 is effective for financial statements for interim and annual periods ending after September 15, 2009. SFAS No. 168 establishes the FASB Accounting Standards Codification (FASB Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with U.S. GAAP. The purpose of the FASB Codification is to simplify U.S. GAAP, without change, by consolidating the numerous accounting rules into logically organized topics. The Company has adopted SFAS No. 168 and therefore all references by the Company to authoritative accounting principles recognized by the FASB reflect the FASB Codification.

RESULTS OF OPERATIONS

The following discussion of the Company's financial condition and results of operations should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report.

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company's results will reflect the seasonal nature of the natural gas business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Net Income and EPS Overview

2009 Compared to 2008—The Company's Earnings Applicable to Common Shareholders was $1.2 million, or $0.11 per common share, for the fourth quarter of 2009 compared to $3.2 million, or $0.53 per common share, for the fourth quarter of 2008. The Company also reported earnings of $9.9 million for the full year period of 2009, compared to $9.6 million for 2008. Earnings per common share were $1.03 for 2009, ($0.62) per share lower than last year's earnings of $1.65. The lower earnings per common share in the fourth quarter and full year period of 2009 primarily reflect higher regulatory and legal expenses in 2009 associated with the devastating ice storm that struck New England in December 2008 and a significant non-recurring regulatory matter.

In 2009 the Company recognized professional fees of approximately $3.0 million related to regulatory and legal matters concerning the Company's preparation and response to the devastating ice storm that struck the New England region on December 11 and 12, 2008. In the fourth quarter of 2009, the Company also recognized a non-recurring accounting charge for a regulatory order that required Fitchburg Gas and Electric Light Company, the Company's Massachusetts combination gas and electric operating utility, to refund $4.9 million of natural gas supply costs, including carrying charges. Excluding these one-time charges, the Company's Earnings Applicable to Common Shareholders was $5.1 million, or $0.47 per common share, for the fourth quarter of 2009 and $15.1 million, or $1.57 per share, for the full year ended December 31, 2009.

In addition to the one-time charges, earnings in 2009 reflect higher gas utility sales margins offset by higher operating, depreciation and interest costs. Natural gas sales margin increased $35.1 million in 2009 compared to 2008, reflecting the contribution to natural gas sales by Northern Utilities and Granite State. Natural gas sales margin also includes the unfavorable effect of a refund of $4.9 million of natural gas supply costs recorded in the fourth quarter of 2009. Electric sales margin increased $0.4 million in 2009 compared to 2008, reflecting higher electric rates offset by lower sales. Total electric kilowatt-hour (kWh) sales decreased 4.5% in 2009 compared to 2008, reflecting lower average usage by customers due to the continued economic slowdown and milder summer weather in 2009. Average summer temperatures in the Company's electric service territories, as measured by cooling degree days, were 31% cooler in 2009 compared to the same period in 2008 and were 26% cooler than normal. Unitil paid common dividends of $1.38 in 2009.

Total Operation & Maintenance (O&M) expenses increased $17.2 million, or 62.5%, in 2009 compared to 2008. The inclusion of Northern Utilities and Granite State for the full year in 2009 accounted for $8.8 million of the increase. In addition, higher compensation and retiree and employee benefit expenses of $2.2 million and net other utility operating costs of $0.4 million contributed to the increase in O&M expenses year over year. As discussed above, in 2009 the Company expensed professional fees of approximately $3.0 million related to regulatory and legal matters concerning the December 2008 Ice Storm. The increase in O&M expenses in 2009 over 2008 also reflects lower O&M recorded in 2008 due to the receipt of a $2.8 million insurance settlement in that year.

Depreciation, Amortization, Taxes and Other expenses increased $13.2 million in 2009 compared to 2008. The increase is largely due to the inclusion of Northern Utilities and Granite State for the full year in 2009, higher depreciation on normal utility plant additions and higher income taxes on higher pre-tax earnings in 2009.

Interest Expense, Net increased $5.3 million in 2009 compared to 2008. The increase is due to the issuance of $90 million of long-term notes issued by Northern Utilities and Granite State in December 2008 to partially finance the acquisition and higher average borrowings during 2009, partially offset by increases in interest income on regulatory assets and Allowance for Funds Used During Construction (AFUDC) in 2009.

The Company's non-regulated energy brokering and advisory services business, Usource, achieved sales margins of $4.3 million in 2009, and contributed $1.6 million to consolidated Earnings, or $0.16 per share for the year compared to earnings of $0.3 million, or $0.06 per share in 2008.

On December 11 and 12, 2008, a severe ice storm struck the New England region, creating extended power outages for many residents of Massachusetts and New Hampshire, including Unitil's electric customers in New Hampshire and the greater Fitchburg, Massachusetts service territory. As discussed above, the Company has received approval from the MDPU and the NHPUC to defer storm restoration costs associated with the repair of damages to its electric distribution system caused by the December 2008 Ice Storm and to request recovery for these costs in Fitchburg's and Unitil Energy's next rate cases. The Company has accrued and deferred, excluding capital construction expenditures, approximately $14.6 million in costs, including carrying charges, for the repair and replacement of electric distribution systems damaged during the storm. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations.

In 2009, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January 2010 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

Between December 2008 and June 2009, the Company sold 4,970,000 shares of its common stock at a price of $20.00 per share in registered public offerings. The Company used the net proceeds of $93.1 million from these offerings to finance the acquisition of Northern Utilities and Granite State and for capital contributions to Unitil's other distribution utilities and the repayment of short-term debt. Overall, the results of operations and net income are reflected over a higher number of average shares outstanding year over year.

2008 Compared to 2007—The Company's Earnings Applicable to Common Shareholders was $9.6 million for 2008, an increase of 12% over 2007 Earnings of $8.6 million. Earnings per common share were $1.65 for 2008, $0.13 per share higher than last year. Earnings in 2008 reflect the acquisitions, on December 1, 2008, of Northern Utilities and Granite State. The acquisitions have increased the share of the company's operating results attributable to gas operations, which have a higher proportion of annual gas sales margin during the winter months.

A more detailed discussion of the Company's 2009 and 2008 results of operations and a year-to-year comparison of changes in financial position are presented below.

Gas Sales, Revenues and Margin

Therm Sales—Overall, Unitil's total therm sales of natural gas increased 278.6% in 2009 compared to 2008, reflecting the contribution to sales by Northern Utilities. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas decreased 0.7% in 2009 compared to 2008, reflecting a decrease of 2.0% in sales to residential customers and flat year over year sales to C&I customers. The decrease in sales to residential customers reflects lower average usage by our customers, due to a slowing economy and energy conservation, partially offset by a colder winter heating season in the first quarter of 2009.

Overall, Unitil's total therm sales of natural gas increased 66.2% in 2008 compared to 2007. Excluding the contribution of the acquisition of Northern Utilities, total therm sales of natural gas increased 1.1% in 2008 compared to 2007, reflecting a decrease of 2.0% in sales to residential customers offset by an increase of 2.7% in sales to C&I customers. The lower sales to residential customers in 2008 reflects a milder winter heating season and lower average usage by our customers reflecting a slowing economy and energy conservation. The increase in gas sales to C&I customers in 2008 reflects increased usage of natural gas in those customers' production operations.

The following table details total therm sales for the last three years, by major customer class:

Therm Sales (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	**2008**	**2007**	**Change**	**Change %**	**Change**	**Change %**
Residential	**36.7**	13.3	10.2	23.4	175.9%	3.1	30.4%
Commercial / Industrial	**142.0**	33.9	18.2	108.1	318.9%	15.7	86.3%
Total	**178.7**	47.2	28.4	131.5	278.6%	18.8	66.2%

Gas Operating Revenues and Sales Margin—The following table details Total Gas Operating Revenue and Gas Sales Margin for the last three years by major customer class:

Gas Operating Revenues and Gas Sales Margin (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	**2008**	**2007**	**$ Change**	**% Change (1)**	**$ Change**	**% Change (1)**
Gas Operating Revenue:							
Residential	**$ 62.0**	$27.5	$18.8	$34.5	60.6%	$ 8.7	25.4%
Commercial / Industrial	**90.8**	29.4	15.4	61.4	107.9%	14.0	41.0%
Total Gas Operating Revenue	**$152.8**	$56.9	$34.2	$95.9	168.5%	$22.7	66.4%
Cost of Gas Sales:							
Purchased Gas	**$ 96.4**	$37.3	$21.3	$59.1	103.9%	$16.0	46.8%
Conservation & Load Management	**1.9**	0.2	0.2	1.7	2.9%	—	—
Total Cost of Gas Sales	**$ 98.3**	$37.5	$21.5	$60.8	106.8%	$16.0	46.8%
Gas Sales Margin	**$ 54.5**	$19.4	$12.7	$35.1	61.7%	$ 6.7	19.6%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $95.9 million, or 168.5%, in 2009 compared to 2008, reflecting the inclusion of Northern Utilities and Granite State for the full year in 2009. Total Gas Operating Revenues include the recovery of the approved cost of sales, which are recorded as Purchased Gas and Conservation and Load Management (C&LM) in Operating Expenses. The increase in Total Gas Operating Revenues in 2009 reflects higher Purchased Gas costs of $59.1 million, higher C&LM revenues of $1.7 million and higher sales margin of $35.1 million.

Purchased Gas and C&LM revenues increased $60.8 million, or 106.8%, of Total Gas Operating Revenues in 2009 compared to 2008, reflecting the inclusion of Northern Utilities and Granite State for the full year in 2009 and the $4.9 million refund of natural gas supply costs recorded in the fourth quarter of 2009. Purchased Gas revenues include the recovery of the approved cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $35.1 million in 2009 compared to 2008, reflecting the contribution to natural gas sales by Northern Utilities and Granite State. Natural gas sales margin also includes the unfavorable effect of a refund of $4.9 million of natural gas supply costs recorded in the fourth quarter of 2009.

Total Gas Operating Revenues increased $22.7 million, or 66.4%, in 2008 compared to 2007, largely reflecting the acquisition of Northern Utilities and Granite State on December 1, 2008 and the 1.1% increase in gas sales, net of the effect of the acquisitions, and higher rates implemented in November 2007. The increase in Total Gas Operating Revenues in 2008 reflects higher Purchased Gas costs of $16.0 million and higher sales margin of $6.7 million.

Natural gas sales margin increased $6.7 million in 2008 compared to 2007. This increase reflects $5.4 million of gas sales margin from Northern Utilities and Granite State and an additional increase of $1.3 million in gas sales margin reflecting higher rates implemented in November 2007 and higher sales to C&I customers.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales—Unitil's total electric kWh sales decreased 4.5% in 2009 compared to 2008. Electric kWh sales to residential customers and C&I customers decreased 2.2% and 6.1%, respectively, in 2009 compared to 2008. The lower electric kWh sales in 2009 compared to 2008 reflect lower average usage by our customers due to the continued regional economic slowdown and milder summer weather in 2009. Average summer temperatures in the Company's electric service territories, as measured by cooling degree days, were 31% cooler in 2009 compared to the same period in 2008 and were 26% cooler than normal.

Unitil's total electric kWh sales decreased 2.7% in 2008 compared to 2007. Electric kWh sales to residential customers and C&I customers decreased 2.2% and 3.0%, respectively, in 2008 compared to 2007. The lower electric kWh sales in 2008 compared to 2007 were driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	2008	2007	Change kWh	Change %	Change kWh	Change %
Residential	**645.9**	660.2	674.8	(14.3)	(2.2%)	(14.6)	(2.2%)
Commercial / Industrial	**972.9**	1,035.7	1068.2	(62.8)	(6.1%)	(32.5)	(3.0%)
Total	**1,618.8**	1,695.9	1,743.0	(77.1)	(4.5%)	(47.1)	(2.7%)

Electric Operating Revenues and Sales Margin—The following table details Total Electric Operating Revenue and Electric Sales Margin for the last three years by major customer class:

Electric Operating Revenues and Electric Sales Margin (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	2008	2007	$ Change	% Change (1)	$ Change	% Change (1)
Electric Operating Revenue:							
Residential	**$108.9**	$114.5	$114.7	$ (5.6)	(2.5%)	$(0.2)	(0.1%)
Commercial / Industrial	**101.0**	113.0	110.3	(12.0)	(5.2%)	2.7	1.2%
Total Electric Operating Revenue	**$209.9**	$227.5	$225.0	$(17.6)	(7.7%)	$ 2.5	1.1%
Cost of Electric Sales:							
Purchased Electricity	**$151.6**	$170.1	$165.4	$(18.5)	(8.1%)	$ 4.7	2.1%
Conservation & Load Management	**3.1**	2.6	3.4	0.5	0.2%	(0.8)	(0.4%)
Total Cost of Electric Sales	**$154.7**	$172.7	$168.8	$(18.0)	(7.9%)	$ 3.9	1.7%
Electric Sales Margin	**$ 55.2**	$ 54.8	$ 56.2	$ 0.4	0.2%	$(1.4)	(0.6%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues decreased by $17.6 million, or 7.7%, in 2009 compared to 2008. Total Electric Operating Revenues include the recovery of approved costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The net decrease in Total Electric Operating Revenues in 2009 reflects lower Purchased Electricity costs of $18.5 million offset by higher C&LM revenues of $0.5 million and higher sales margin of $0.4 million.

Purchased Electricity and C&LM revenues decreased $18.0 million, or 7.9%, of Total Electric Operating Revenues in 2009 compared to 2008, primarily reflecting lower sales volumes and lower electric commodity prices, partially offset by higher spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the approved cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $0.4 million in 2009 compared to 2008. The increase in electric sales margin reflects higher rates offset by lower sales volumes. Total electric sales decreased 4.5% in 2009 compared to 2008, reflecting lower average usage by our customers due to the continued economic slowdown and milder summer weather in 2009.

Total Electric Operating Revenues increased by $2.5 million, or 1.1%, in 2008 compared to 2007. The net increase in Total Electric Operating Revenues in 2008 reflects higher Purchased Electricity costs of $4.7 million offset by lower C&LM revenues of $0.8 million and lower sales margin of $1.4 million.

Electric sales margin decreased $1.4 million in 2008 compared to 2007. The decrease in electric sales margin primarily reflects lower sales volumes, partially offset by higher electric base rates implemented in March of 2008. Total electric sales decreased 2.7% in 2008 compared to 2007 driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

Operating Revenue—Other

Total Other Revenue increased $0.5 million in 2009 compared to 2008 and $0.1 million in 2008 compared to 2007. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (millions)

				2009 vs. 2008		2008 vs. 2007	
	2009	**2008**	**2007**	**$ Change**	**% Change**	**$ Change**	**% Change**
Usource	**$4.3**	$3.8	$3.7	$0.5	13.2%	$0.1	2.7%
Total Other Revenue	**$4.3**	$3.8	$3.7	$0.5	13.2%	$0.1	2.7%

Operating Expenses

Purchased Gas—Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $59.1 million, or 158.4%, in 2009 compared to 2008. This increase primarily reflects the inclusion of Northern Utilities for the full year in 2009. The Company recovers the approved costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in approved expenses do not affect earnings.

In 2008, Purchased Gas increased $16.0 million, or 75.1%, compared to 2007. The increase in Purchased Gas largely reflects the acquisition of Northern Utilities and Granite State on December 1, 2008. In addition to the increase in Purchased Gas due to the acquisitions, Purchased Gas increased $1.5 million, or 7.0%, in 2008 compared to 2007 reflecting higher natural gas commodity prices and higher sales to C&I customers.

Purchased Electricity—Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity decreased $18.5 million, or 10.9%, in 2009 compared to 2008. This decrease reflects lower sales volumes and lower electric commodity prices. The Company recovers the approved costs of Purchased Electricity in its rates at cost and therefore changes in approved expenses do not affect earnings.

In 2008, Purchased Electricity expenses increased $4.7 million, or 2.8%, compared to 2007, reflecting higher electric commodity prices partially offset by lower sales volumes.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. Total O&M expenses increased $17.2 million, or 62.5%, in 2009 compared to 2008. The inclusion of Northern Utilities and Granite State for the full year in 2009 accounted for $8.8 million of the increase. In addition, higher compensation and retiree and employee benefit expenses of $2.2 million and net other utility operating costs of $0.4 million contributed to the increase in O&M expenses year over year. As discussed above, in 2009 the Company expensed professional fees of approximately $3.0 million related to regulatory and legal matters concerning the December 2008 Ice Storm. The increase in O&M expenses in 2009 over 2008 also reflects lower O&M recorded in 2008 due to the receipt of a $2.8 million insurance settlement in that year.

In 2008, total O&M expense increased $1.3 million, or 5.0%, compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.9 million of the increase. In addition, the increase in O&M expenses reflects higher employee and retiree compensation and benefit expenses of $2.7 million, including increased employee benefits of $1.4 million, driven primarily by higher medical claims in 2008 and higher employee benefits related to staffing increases, and higher salaries and compensation of $1.3 million, due to normal annual increases and staffing additions. Also contributing to the increase in O&M expenses were higher utility operating costs of $0.3 million and higher bad debt expenses of $0.3 million, partially offset by a reduction of $2.8 million from the proceeds of an insurance settlement and lower professional fees of $0.1 million.

Conservation & Load Management—C&LM expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 60% of these costs are related to electric operations and 40% to gas operations.

Total C&LM expenses increased by $2.2 million, in 2009 compared to 2008. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total C&LM expenses decreased by $0.8 million in 2008 compared to 2007.

Depreciation and Amortization—Depreciation and Amortization expense increased $8.3 million, or 43.5% in 2009 compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009 and higher depreciation on normal utility plant additions.

In 2008, Depreciation and Amortization expense increased $1.3 million, or 7.3%, compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.6 million of the increase. In addition, the increase in Depreciation and Amortization expense reflects higher depreciation on normal utility plant additions.

Local Property and Other Taxes—Local Property and Other Taxes increased by $4.1 million, or 63.1%, in 2009 compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009, and higher local property tax rates on higher levels of utility plant in service.

In 2008, Local Property and Other Taxes increased by $0.9 million, or 16.1%, compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.3 million of the increase. In addition, the increase in Local Property and Other Taxes reflects higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes—Federal and State Income Taxes increased by $0.8 million in 2009 compared to 2008 due to higher pre-tax operating income in 2009 compared to 2008 (See Note 8 to the accompanying Consolidated Financial Statements).

Federal and State Income Taxes decreased by $0.1 million in 2008 compared to 2007 due to a lower effective tax rate year over year due to the recognition of higher permanent book/tax differences partially offset by higher pre-tax operating income in 2008 compared to 2007.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) was flat in 2009 compared to 2008.

Other Non-operating Expenses (Income) increased by $0.1 million in 2008 compared to 2007. This change reflects an adjustment of $0.1 million in conjunction with the Company's electric base distribution rate increase in Massachusetts which was implemented in March of 2008.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated (See Note 4 to the accompanying Consolidated Financial Statements).

Interest Expense, net increased $5.3 million in 2009 compared to 2008. The increase is primarily due to the issuance of $90 million of long-term notes issued by Northern Utilities and Granite State in December 2008 to partially finance the acquisition and higher average borrowings during 2009, partially offset by increases in interest income on regulatory assets and AFUDC in 2009.

In 2008, Interest Expense, net, rose by $0.9 million compared to 2007. The acquisitions of Northern Utilities and Granite State accounted for $0.3 million of the increase. The increase associated with the acquisitions is due to $0.5 million of interest expense from the issuance of long-term notes by Northern Utilities and Granite State in December 2008, partially offset by interest income on regulatory mechanisms. In addition to the increase related to the acquisitions, the remaining $0.6 million increase in Interest Expense, net reflects higher debt outstanding and lower interest earned on regulatory assets compared to the prior period.

LIQUIDITY, COMMITMENTS AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

On December 18, 2009, both Unitil Energy and Northern Utilities priced long-term financings scheduled to close in the first quarter of 2010:

(i) Unitil Energy priced $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds were priced at a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Unitil Energy anticipates closing this long-term financing in March 2010.

(ii) Northern Utilities priced $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes were priced at a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Northern Utilities anticipates closing this long-term financing in March 2010.

The Unitil Energy and Northern Utilities securities offered will not be, and have not been, registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

The Company, along with its subsidiaries, are individually and collectively members of the Unitil Cash Pool (the Cash Pool). The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool allows for an efficient exchange of cash among the Company and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on actual interest costs from lenders under the Company's revolving credit facility. At December 31, 2009 and 2008, all of the Company's subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

As of December 31, 2009 and 2008, the Company had $64.5 million and $35.0 million, respectively, in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of December 31, 2009 and 2008, the Company was in compliance with the financial covenants contained in the revolving credit facility agreement.

The continued availability of various methods of financing, as well as the choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of earnings, cash flows, financial position; and the competitive pricing offered by financing sources.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2009.

		Payments Due by Period			
Contractual Obligations (millions) as of December 31, 2009	**Total**	**2010**	**2011-2012**	**2013-2014**	**2015 & Beyond**
Long-term Debt Obligations	$249.3	$ 0.4	$ 1.0	$ 3.0	$244.9
Interest on Long-term Debt Obligations	284.0	17.9	35.7	35.6	194.8
Gas Supply Contracts [(1)]	190.5	61.6	58.0	47.6	23.3
Power Supply Contract Obligations	34.7	13.0	17.8	1.8	2.1
Other	5.5	1.7	2.5	0.8	0.5
Total Contractual Cash Obligations	$764.0	$94.6	$115.0	$88.8	$465.6

(1) Primarily reflects demand charges associated with natural gas transportation contracts.

The Company and its subsidiaries have material energy supply commitments that are discussed in Note 6 to the accompanying Consolidated Financial Statements. Cash outlays for the purchase of electricity and natural gas to serve customers are subject to reconciling recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over-collected cash over subsequent periods of less than a year.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2009, there were approximately $30.5 million of guarantees outstanding and the longest term guarantee extends through December 31, 2010. Of this amount, $8.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed below.

Northern enters into asset management agreements under which Northern releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $10.0 million and $31.8 million outstanding at December 31, 2009 and December 31, 2008, respectively, related to these asset management agreements.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.3 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Benefit Plan Funding

The Company, along with its subsidiaries, made cash contributions to its Pension Plan in the amount of $4.2 million and $2.8 million in 2009 and 2008, respectively. The Company, along with its subsidiaries (other than Northern Utilities and Granite State), contributed $2.8 million and $2.7 million to Voluntary Employee Benefit Trusts (VEBT) in 2009 and 2008, respectively. The Company expects to contribute approximately $4.0 million and $2.8 million, respectively, to fund its Pension and PBOP Plans in 2010. The Company, along with its subsidiaries, expects to continue to make contributions to its Pension Plan and the VEBTs in future years in amounts consistent with the amounts recovered in the distribution utilities' rates for these other postretirement benefit costs. (See Note 9 to the accompanying Consolidated Financial Statements.)

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements. (See Note 4 to the accompanying Consolidated Financial Statements.)

Cash Flows

On December 1, 2008, the Company acquired Northern Utilities and Granite State. Cash flow results for 2009 include a full-year of activity for the acquired companies, while cash flow results for 2008 include only one month of activity for the acquired companies. Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for 2009 and 2008.

(millions)	**2009**	**2008**
Cash Provided by Operating Activities	**$50.9**	$47.3

Cash Provided by Operating Activities—Cash Provided by Operating Activities was $50.9 million in 2009, an increase of $3.6 million over the comparable period in 2008. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes, was $44.5 million in 2009 compared to $36.2 million in 2008, representing an increase of $8.4 million. Working capital changes in Current Assets and Liabilities resulted in a $29.4 million source of cash in 2009, compared to a $0.7 million use of cash in 2008, representing an increased source of cash of $30.1 million primarily due to a reduction in Gas Inventory of 17.3 million and a decrease in Accrued Revenue of $12.9 million. Deferred Regulatory and Other Charges resulted in a $24.6 million use of cash, compared to a $2.6 million source of cash in

2008, primarily related to the funding in 2009 of non-recurring Deferred Regulatory Charges related to the December 2008 Ice Storm of $14.0 million. All other Operating Activities resulted in a source of cash of $1.6 million in 2009, compared to a source of cash of $9.2 million in 2008.

(millions)	2009	2008
Cash (Used in) Investing Activities	**$(65.6)**	$(238.2)

Cash (Used in) Investing Activities—Cash Used in Investing Activities was $65.6 million for 2009 compared to $238.2 million used in 2008. Northern Utilities and Granite State acquisition costs were $6.9 million in 2009 compared to $209.9 million in 2008. Capital expenditures for property, plant and equipment additions were $58.7 million in 2009 compared to $28.3 million in 2008, representing an increased use of cash of $30.4 million primarily due to the acquisition of Northern Utilities and Granite State. Cash Used in Investing Activities in 2008 included $209.9 million for the Company's acquisition of Northern Utilities and Granite State on December 1, 2008. Capital expenditures are projected to be approximately $60 million in 2010, reflecting normal electric and gas utility system additions.

(millions)	2009	2008
Cash Provided by Financing Activities	**$10.9**	$197.8

Cash Provided by Financing Activities—Cash Provided by Financing Activities was $10.9 million in 2009 compared to $197.8 million in 2008. In 2009, sources of cash from financing activities included proceeds from the issuance of common stock of $56.4 million, and uses of cash included a decrease in Gas Inventory Financing of $21.8 million, regular quarterly dividend payments on common and preferred stock of $13.2 million, the repayment of short-term debt of $9.6 million and the scheduled repayment of long-term debt of $0.4 million. Cash Provided by Financing Activities in 2008 primarily reflects the financing activity related to the Company's acquisition of Northern Utilities and Granite State on December 1, 2008.

FINANCIAL COVENANTS AND RESTRICTIONS

The agreements under which the Company's and its subsidiaries' long-term debt were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations and covenants restricting the ability to (i) pay dividends, (ii) incur indebtedness and liens, (iii) merge or consolidate with another entity or (iv) sell, lease or otherwise dispose of all or substantially all assets. (See Note 4 to the accompanying Consolidated Financial Statements.)

The long-term debt and preferred stock of Unitil, Unitil Energy, Fitchburg, Northern Utilities, Granite State and Unitil Realty are privately held, and the Company does not issue commercial paper. For these reasons, the debt securities of Unitil and its subsidiaries are not publicly rated.

The Company's revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter.

The Company and its subsidiaries are currently in compliance with all such covenants in these debt instruments.

DIVIDENDS

Unitil's annualized common dividend was $1.38 per common share in 2009, 2008 and 2007. Unitil's dividend policy is reviewed periodically by the Board of Directors. Unitil has maintained an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2010 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

LEGAL PROCEEDINGS

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the December 2008 Ice Storm. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company continues to believe the suit is without merit, and will defend itself vigorously.

REGULATORY MATTERS

Overview (Unitil Energy, Fitchburg, and Northern Utilities): Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territory at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next two to four years, is $63.0 million as of December 31, 2009 including $17.7 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans. See Note 6 for additional information on these filings.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Unitil was able to restore power to over 80 percent of its customers by day seven, and its final customers, including those with individual service problems, were restored in Massachusetts by December 24, 2008. As a result of the ice storm, the Company has spent approximately $23 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.3 million related to capital construction and $14.6 million, including carrying charges, which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million in 2009 for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

On January 7, 2009, the MDPU opened an investigation into the preparation and response of the Massachusetts electric distribution companies to the December 2008 Ice Storm. Evidentiary hearings before the MDPU concerning Fitchburg's storm response were held in May, 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service. As a result, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices to address: Unitil's strategic planning processes; its staffing decisions to the extent to which they affect Fitchburg; its management and control of Fitchburg, including resource allocation decisions made among Unitil's three subsidiary companies; and customer relations. The order also directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

On July 28, 2009, Fitchburg filed with the MDPU a petition for approval to defer and record as a regulatory asset approximately $11.5 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. On December 30, 2009, the MDPU approved the request. The order of approval stated that it made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. Fitchburg anticipates filing its next rate case during the second quarter of 2010. As of December 31, 2009, Fitchburg has deferred approximately $12.3 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On August 26, 2009, Unitil Energy filed a petition with the NHPUC requesting an accounting order authorizing Unitil Energy to record as a regulatory asset approximately $2 million in expenses associated with network damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's next base rate case. On November 9, 2009, the NHPUC granted the requested accounting order, clarifying that such issues as the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are issues that will be deferred to Unitil Energy's next rate case. Unitil Energy anticipates filing its next rate case during the second quarter of 2010. As of December 31, 2009, Unitil Energy has deferred approximately $2.3 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On December 3, 2009, the NHPUC issued its final report regarding its 'after action' review of the December 2008 Ice Storm. The after action review was a non-docketed investigation by the NHPUC of utility emergency preparedness and response. The report stated that the NHPUC will commence an adjudicative proceeding to examine the reasonableness of the timing of Unitil's response to the December 2008 Ice Storm, the priorities of its restorations and the allocation of its resources in New Hampshire and Massachusetts. On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. This matter remains pending.

Unitil Energy: On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On January 16, 2009, the NHPUC issued its decision in this matter, concluding that such rate mechanisms should only be implemented on a company-by-company basis in the context of an examination of company-specific costs and revenues, service territory, customer mix and rate base investment. On March 23, 2009, the NHPUC denied a Motion for Rehearing of this matter.

In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009, Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources.

Fitchburg—Electric Operations: On November 25, 2009, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery is proposed through a Transition Charge Surcharge of $0.004 per kWh. Changes to the Pension / PBOP Adjustment and Residential Assistance Adjustment Factor were proposed in other proceedings. The rates were approved effective January 1, 2010, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2008 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting the items required by House Bill 4329.

Fitchburg—Gas Operations: Fitchburg provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current distribution rates were approved by the MDPU in 2007. Fitchburg's customers may purchase natural gas supplies from third-party vendors or purchase their natural gas from Fitchburg under regulated rates and tariffs. Fitchburg collects its natural gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On March 12, 2009, the MDPU opened an investigation into Fitchburg's gas procurement practices. On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

During the summer of 2009, Fitchburg operated its gas system entirely on local production from LNG for approximately three months due to construction on the lateral from Tennessee Gas Pipeline, which is the sole source of pipeline gas to Fitchburg. During this time Fitchburg provided gas LNG supply to all firm sales customers and also to the retail marketers for delivery to firm customers who have contracted for third-party supply. Fitchburg's management of this project was reviewed by the MDPU during its last Integrated Resource Plan proceeding, before the shutdown occurred. In its order, the MDPU stated it would investigate the costs associated with the shutdown in Fitchburg's March 2010 Cost of Gas Adjustment Clause filing when its actual costs will be reconciled with its projected costs.

Fitchburg—Other: On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, including company-specific rate cases. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012.

On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, and special tariffs to allow the net metering of customer-owned renewable generation. These matters, under review in separately designated dockets, remain pending, except for net metering tariffs which were approved by the MDPU effective December 1, 2009.

Northern Utilities: On December 1, 2008 Unitil completed the purchase of Northern Utilities from Bay State and Granite State from NiSource. Unopposed settlement agreements resolving all outstanding issues and recommending approval of the acquisition were approved by the NHPUC on October 10, 2008, and by the MPUC on November 5, 2008. Pursuant to its expanded authority over holding company mergers under the GC Act, the MDPU also reviewed the transaction and issued its approval on November 18, 2008.

The New Hampshire and Maine settlement agreements included the following provisions with respect to the accounting and rates of Northern Utilities:

- approval of Northern Utilities' accounting deferral and 10-year amortization of transaction costs and transition costs resulting from the Company's acquisition of Northern Utilities and the Company's agreement not to seek recovery of these costs, or the transaction or transition costs of any other utility subsidiary, in rates;
- agreement that synergy savings resulting from the acquisition of Northern Utilities will be retained by the Company until the next base rate change and then will flow to customers;
- agreement not to request a base rate change for Northern Utilities before November 1, 2010 unless (i) Northern Utilities' projected annual revenues are more than 8% below the level of total 2007 distribution revenues or (ii) the MPUC or NHPUC, as applicable, approves a plan to subject Granite State's rates to state regulation;

- agreement to allow Northern Utilities to recover prudently incurred integration costs for capitalized expenditures to build or upgrade systems or facilities required to independently operate Northern Utilities;
- agreement not to seek recovery in Northern Utilities' rates of any acquisition premium resulting from Unitil's acquisition of Northern Utilities and that any acquisition adjustment (positive or negative) shall be accounted for below the line for ratemaking purposes over a 10-year period;
- agreement to hold Northern Utilities' customers harmless for the elimination of historical accumulated deferred income tax liabilities resulting from its Internal Revenue Service Section 338(h)(10) election;
- agreement to use an imputed weighted cost of debt for ratemaking purposes until Northern Utilities' existing debt instruments would have matured; and
- agreement not to change Northern Utilities' existing depreciation rates for its Maine division until approved in the next general rate case.

The settlement agreements contained the following commitments related to Granite State:

- agreement to work collaboratively with the parties to the settlements to design and to conduct a comprehensive study of the issues and costs for modification of the physical, operational, regulatory, and corporate structure necessary for state regulation of Granite State and to provide a report within one year of the closing; and
- authorization for Northern Utilities to execute a firm service contract with Granite State for 100,000 Dekatherms (Dth) of capacity at Granite State's current recourse rate of $1.6666 / Dth for the period November 1, 2008 through October 31, 2010.

On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation (NOPVs) of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern's distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at December 31, 2009 was $2.3 million.

On June 27, 2008, the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in the Portland and Westbrook service areas. Northern Utilities anticipates filing testimony and a proposal for a replacement program with the MPUC by mid-February of 2010, and that proceedings will continue on this matter during the second and third quarters 2010.

See Note 6 to the accompanying Consolidated Financial Statements for additional information on Regulatory Matters.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former MGP site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows

Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800's through the mid 1900's. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

See Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES AND EMPLOYEE RELATIONS

As of December 31, 2009, the Company and its subsidiaries had 431 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2009, 156 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two agreements expire on May 31, 2010, one agreement expires on June 5, 2010 and one agreement expires on March 31, 2012. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with U.S. GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. In accordance with the FASB Codification, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The FASB Codification specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets". If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities".

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided in Note 1 thereto. The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements.

The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The FASB Codification requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2009 and 2008, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000 and $200,000, respectively, in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2009 and 2008, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $735,000 and $675,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $576,000 and $531,000, respectively. (See Note 9 to the accompanying Consolidated Financial Statements).

Income Taxes—Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes.

Depreciation—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2009, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements" in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 8, "Income Taxes," Note 5, "Energy Supply," Note 9, "Benefit Plans," and Note 6, "Commitment and Contingencies," to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please also refer to Item 1A. "Risk Factors."

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 3.4%, 3.8%, and 5.6% during 2009, 2008, and 2007, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the years ended December 31, 2009, 2008 and 2007. We also have audited Unitil Corporation and subsidiaries' internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unitil Corporation and subsidiaries as of December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Unitil Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in (COSO).

Caturano and Company, P.C.

Boston, Massachusetts
February 10, 2010

[THIS PAGE INTENTIONALLY LEFT BLANK]

CONSOLIDATED STATEMENTS OF EARNINGS

(Millions, except common shares and per share data)

Year Ended December 31,	2009	2008	2007
Operating Revenues:			
Gas	**$152.8**	$ 56.9	$ 34.2
Electric	**209.9**	227.5	225.0
Other	**4.3**	3.8	3.7
Total Operating Revenues	**367.0**	288.2	262.9
Operating Expenses:			
Purchased Gas	**96.4**	37.3	21.3
Purchased Electricity	**151.6**	170.1	165.4
Operation and Maintenance	**44.7**	27.5	26.2
Conservation & Load Management	**5.0**	2.8	3.6
Depreciation and Amortization	**27.4**	19.1	17.8
Provisions for Taxes:			
Local Property and Other	**10.6**	6.5	5.6
Federal and State Income	**5.2**	4.4	4.5
Total Operating Expenses	**340.9**	267.7	244.4
Operating Income	**26.1**	20.5	18.5
Other Non-Operating Expenses	**0.3**	0.3	0.2
Income Before Interest Expense	**25.8**	20.2	18.3
Interest Expense, net	**15.8**	10.5	9.6
Net Income	**10.0**	9.7	8.7
Less Dividends on Preferred Stock	**0.1**	0.1	0.1
Earnings Applicable to Common Shareholders	**$ 9.9**	$ 9.6	$ 8.6
Average Common Shares Outstanding (000's)—Basic	**9,647**	5,830	5,659
Average Common Shares Outstanding (000's)—Diluted	**9,647**	5,830	5,672
Earnings per Common Share—Basic and Diluted	**$ 1.03**	$ 1.65	$ 1.52

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS *(Millions)*

ASSETS

December 31,	2009	2008
Utility Plant:		
Electric	**$302.3**	$289.0
Gas	**325.5**	304.2
Common	**28.9**	30.5
Construction Work in Progress	**26.0**	17.7
Utility Plant	**682.7**	641.4
Less: Accumulated Depreciation	**233.0**	218.6
Net Utility Plant	**449.7**	422.8
Current Assets:		
Cash	**7.7**	11.5
Accounts Receivable—(Net of Allowance for Doubtful Accounts of $2.5 and $3.0)	**33.5**	39.7
Accrued Revenue	**44.0**	56.9
Gas Inventory	**14.3**	31.6
Material and Supplies	**2.6**	2.7
Prepayments and Other	**4.7**	5.9
Total Current Assets	**106.8**	148.3
Noncurrent Assets:		
Regulatory Assets	**144.5**	146.2
Other Noncurrent Assets	**24.2**	15.9
Total Noncurrent Assets	**168.7**	162.1
TOTAL	**$725.2**	$733.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (cont.) *(Millions)*

CAPITALIZATION AND LIABILITIES

December 31,	2009	2008
Capitalization:		
Common Stock Equity	**$193.1**	$139.5
Preferred Stock	**2.0**	2.0
Long-Term Debt, Less Current Portion	**248.9**	249.3
Total Capitalization	**444.0**	390.8
Current Liabilities:		
Long-Term Debt, Current Portion	**0.4**	0.4
Accounts Payable	**25.1**	28.5
Short-Term Debt	**64.5**	74.1
Energy Supply Contract Obligations	**23.1**	49.8
Other Current Liabilities	**16.6**	33.8
Total Current Liabilities	**129.7**	186.6
Deferred Income Taxes	**39.8**	31.1
Noncurrent Liabilities:		
Energy Supply Contract Obligations	**21.7**	34.6
Retirement Benefit Obligations	**65.5**	67.4
Environmental Obligations	**14.3**	12.3
Other Noncurrent Liabilities	**10.2**	10.4
Total Noncurrent Liabilities	**111.7**	124.7
TOTAL	**$725.2**	$733.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS (Millions)

Year Ended December 31,	2009	2008	2007
Operating Activities:			
Net Income	**$ 10.0**	$ 9.7	$ 8.7
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**27.4**	19.1	17.8
Deferred Taxes Provision	**7.1**	7.4	(0.9)
Changes in Current Assets and Liabilities:			
Accounts Receivable	**6.2**	(6.4)	(2.4)
Accrued Revenue	**12.9**	(10.3)	1.1
Gas Inventory	**17.3**	—	—
Accounts Payable	**(3.4)**	11.4	(2.2)
All Other Current Assets and Liabilities	**(3.6)**	4.6	(1.1)
Deferred Regulatory and Other Charges	**(24.6)**	2.6	3.5
Other, net	**1.6**	9.2	2.3
Cash Provided by Operating Activities	**50.9**	47.3	26.8
Investing Activities:			
Property, Plant and Equipment Additions	**(58.7)**	(28.3)	(32.5)
Acquisitions, net (See Note 2)	**(6.9)**	(209.9)	—
Cash (Used In) Investing Activities	**(65.6)**	(238.2)	(32.5)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**(9.6)**	55.3	(7.2)
Proceeds from Issuance of Long-Term Debt	**—**	90.0	20.0
Repayment of Long-Term Debt	**(0.4)**	(0.4)	(0.3)
Net Increase (Decrease) in Gas Inventory Financing	**(21.8)**	24.0	—
Dividends Paid	**(13.2)**	(8.1)	(7.9)
Proceeds from Issuance of Common Stock	**56.4**	37.4	1.5
Other, net	**(0.5)**	(0.4)	(0.4)
Cash Provided by Financing Activities	**10.9**	197.8	5.7
Net Increase (Decrease) in Cash	**(3.8)**	6.9	—
Cash at Beginning of Year	**11.5**	4.6	4.6
Cash at End of Year	**$ 7.7**	$ 11.5	$ 4.6
Supplemental Information:			
Interest Paid	**$ 19.3**	$ 12.5	$ 12.2
Income Taxes Paid (Refunded)	**$ (3.8)**	$ (0.5)	$ 5.3

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2007	$ 63.5	$ 34.3	**$ 97.8**
Net Income for 2007		8.7	**8.7**
Dividends		(7.9)	**(7.9)**
Shares Issued Under Stock Plans	0.8		**0.8**
Issuance of 38,303 Common Shares	1.0		**1.0**
Balance at December 31, 2007	65.3	35.1	**100.4**
Net Income for 2008		9.7	**9.7**
Dividends		(8.0)	**(8.0)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 32,754 Common Shares	0.8		**0.8**
Issuance of 2,000,000 Common Shares (See Note 3)	36.2		**36.2**
Balance at December 31, 2008	102.7	36.8	**139.5**
Net Income for 2009		10.0	**10.0**
Dividends		(13.2)	**(13.2)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 43,615 Common Shares	0.9		**0.9**
Issuance of 2,970,000 Common Shares (See Note 3)	55.5		**55.5**
Balance at December 31, 2009	**$159.5**	**$ 33.6**	**$193.1**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the Acquisitions). Bay State is a wholly owned subsidiary of NiSource.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the "distribution utilities").

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—The Company's consolidated financial statements include the accounts of Unitil and all of its wholly owned subsidiaries and all intercompany transactions are eliminated in consolidation. The operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from December 1, 2008 through December 31, 2009.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)	December 31, 2009	December 31, 2008
Energy Supply Contract Obligations	**$ 34.7**	$ 52.7
Deferred Restructuring Costs	**28.3**	27.8
Generation-related Assets	**—**	0.8
Subtotal—Restructuring Related Items	**63.0**	81.3
Retirement Benefit Obligations	**43.7**	45.5
Income Taxes	**14.5**	16.0
Environmental Obligations	**22.7**	21.6
Deferred Storm Charges	**14.6**	—
Other	**7.9**	10.1
Total Regulatory Assets	**$166.4**	$174.5
Less: Current Portion of Regulatory Assets (1)	**21.9**	28.3
Regulatory Assets—noncurrent	**$144.5**	$146.2

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. Under the Independent System Operator—New England (ISO-NE) Financial Assurance Policy (Policy), Unitil's affiliates Unitil Energy, Fitchburg and Unitil Power are required to provide assurance of their ability to satisfy their obligations to ISO-NE. Under this Policy, Unitil's affiliates provide cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2009 and 2008, the Unitil affiliates had deposited $4.5 million and $3.7 million, respectively to satisfy their ISO-NE obligations. In addition, Northern Utilities has cash margin deposits to satisfy requirements for its natural gas hedging program. On December 31, 2009 and 2008, there was $2.9 million and $7.0 million, respectively, deposited for this purpose.

Goodwill and Intangible Assets—As a result of the acquisitions of Northern Utilities and Granite State, the Company recognized a bargain purchase adjustment as a reduction to Utility Plant, to be amortized over a ten year period, beginning with the date of the Acquisitions, as authorized by regulators. (See Note 2).

Off-Balance Sheet Arrangements—As of December 31, 2009, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases (See Note 4).

Investments and Trading Activities—The Company invests in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for accounting purposes.

Derivatives—The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases New York Mercantile Exchange (NYMEX) futures that correspond to the associated delivery month. Any gains or losses on the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company records gains and losses as regulatory liabilities or assets, recognizes such gains or losses in Purchased Gas and these gains and losses are passed through to customers through rate reconciling mechanisms.

As of December 31, 2009, the Company had 1.9 billion cubic feet (BCF) outstanding in natural gas purchase contracts under its hedging program. The following tables provide information on the hedging instruments for 2009.

Fair Value of Derivatives Designated as Hedging Instruments as of December 31, 2009 ($ millions)

Description	Balance Sheet Location	Fair Value
NYMEX Contracts	Current and NonCurrent Liabilities	$2.3

Description	Amount of Gain (Loss) Recognized in Regulatory Asset / Liability for Derivatives as of December 31, 2009	Location of Gain (Loss) Reclassified from Regulatory Asset / Liability into Consolidated Statement of Earnings	Amount of Gain (Loss) Reclassified from Regulatory Asset / Liability into Consolidated Statement of Earnings for 2009
NYMEX Contracts (1)	$(2.9)	Purchased Gas	$(9.3)

(1) Includes approximately $0.6 million of loss on contracts designated for January 2010 that were physically sold in December 2009 and the impact on the Consolidated Balance Sheet has been deferred until January 2010 when the natural gas is used.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition—Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates. See Note 9.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2009, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below. (See Note 6).

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 3.24%, 4.58% and 5.73% in 2009, 2008 and 2007, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At December 31, 2009 and December 31, 2008, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $37.2 million and $33.9 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. Depreciation provisions for Unitil's utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2009 – 4.02%, 2008 – 3.94% and 2007 – 4.29%.

Environmental Matters—The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has or will recover substantially all of the costs of the environmental remediation work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 6, Commitments and Contingencies. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation using the fair value-based method (See Note 3).

Sales and Consumption Taxes—The Company bills its customers sales tax in Massachusetts and Maine and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

Income Taxes—Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets.

Dividends—The Company is currently paying a dividend at an annual rate of $1.38 per common share. The Company's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Other Recently Issued Pronouncements—In May 2009, the FASB issued FASB ASC 855, "Subsequent Events", (ASC 855) (originally issued as SFAS No. 165, Subsequent Events), effective for interim and annual reporting periods ending after June 15, 2009. ASC 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company adopted ASC 855 and it did not have an impact on the Company's Consolidated Financial Statements. The Company evaluated all events or transactions that occurred after December 31, 2009 up through February 9, 2010.

On April 9, 2009, the FASB issued ASC 825, "Financial Instruments", (ASC 825) (originally issued as FASB Staff Position No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments".) ASC 825 requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. ASC 825 also requires those disclosures in summarized financial information at interim reporting periods. ASC 825 is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company has adopted ASC 825 and included the required disclosures in the Notes to the Company's Consolidated Financial Statements. See Note 4 for relevant disclosures on the fair value of the Company's long-term debt and Note 9 for relevant disclosures on the fair value of the Company's defined benefit pension and other postretirement plan assets.

On December 30, 2008, the FASB issued ASC 715, "Compensation—Retirement Benefits", (ASC 715) (originally issued as FASB Staff Position No. FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets") to provide guidance on an employers' disclosures about plan assets of a defined benefit pension or other postretirement plan. The disclosures about plan assets required by ASC 715 are to be provided for fiscal years ending after December 15, 2009. The Company has adopted ASC 715 and included the required disclosures in the Notes to the Company's Consolidated Financial Statements. See Note 9.

Reclassifications—Based on the Company's analysis certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation, principally including the reclassification of $7.8 million of Accounts Payable to Energy Supply Obligations and $2.0 million of Accrued Revenue to Other Current Liabilities.

Note 2: Acquisitions

On December 1, 2008, the Company purchased (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource pursuant to the Stock Purchase Agreement (SPA) dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil. The aggregate purchase price for the Acquisitions was $209.2 million, comprised of $160 million in cash, plus an additional working capital adjustment of $49.2 million. The largest component of working capital was approximately $30.0 million of natural gas storage inventory.

The Company accounted for the Acquisitions under the purchase method of accounting for business combinations, in accordance with FASB Statement No. 141, "Business Combinations" ("SFAS No. 141") and the FASB Codification on business combinations. Accordingly, the Company recognized its estimate of the bargain purchase price (see "Plant Acquisition Adjustment" in the table below) at December 1, 2008. The process of valuing the assets, liabilities and transaction, transition and financing costs as a result of the Acquisitions was completed in 2009. As a result, the Company has recognized adjustments to its original estimate of the Plant Acquisition Adjustment (PAA) during 2009.

The adjusted PAA is ($24.8 million), a decrease of $3.5 million from the original estimate of ($28.3 million). The adjusted transaction and transition Costs is an increase of $6.9 million over the original estimate, reflecting additional costs to complete the acquisition and financing. Partially offsetting the decrease in the PAA estimate due to the additional transaction and transition Costs were subsequent payments, cash settlements between the purchaser and seller and other post-closing adjustments reflecting changes to working capital, Net Utility Plant and Regulatory Liabilities.

The revised purchase price allocations are as follows:

Purchase Price Allocation
($ Millions)

	December 1, 2008
Equity Purchase Price	$ 160.0
Plus: Working Capital Adjustment	49.2
Aggregate Purchase Price	209.2
Transaction and Transition Costs	14.5
Total Cash Purchase Price	223.7
Allocation To:	
Book Value of Net Utility Plant	(197.0)
Cash Acquired	(6.9)
Accounts Receivable and Other Current Assets	(21.2)
Accrued Revenue	(7.0)
Gas Inventory	(32.3)
Regulatory Assets	(34.3)
Accounts Payable and Other Current Liabilities	20.4
Regulatory Liabilities	29.8
Plant Acquisition Adjustment	**$ (24.8)**

In accordance with settlement agreements between the Company, the New Hampshire Public Utilities Commission (NHPUC) and the Maine Public Utilities Commission (MPUC) regarding the Acquisitions, the Company has agreed (i) not to seek recovery of transaction and transition costs in rates and (ii) for regulatory accounting purposes, to amortize, over a ten year period, the transaction and transition costs co-terminus with the Plant Acquisition Adjustment. See Note 12.

Note 3: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

As of August 21, 2008 the Company's common stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's common stock trades under the symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 10,836,759, and 7,791,617 of common shares outstanding at December 31, 2009 and December 31, 2008, respectively.

Unitil Corporation Common Stock Offering—On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2008 Offering). As part of this 2008 common stock offering, the underwriters exercised an over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the 2008 Offering including the over-allotment were approximately $41.9 million. On May 27, 2009, the Company issued and sold 2,400,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2009 Offering). As part of the 2009 Offering, the underwriters exercised an over-allotment option and purchased an additional 300,000 shares of the Company's common stock in June 2009. The Company's net increase to Common

Equity and Cash proceeds from the 2009 Offering including the over-allotment was approximately $51.2 million. The combined total net increase to Common Equity and Cash proceeds from the 2008 Offering and 2009 Offering of $93.1 million (after payment of underwriting discount, but excluding offering expenses) was used to (i) repay all amounts outstanding under the bank credit facility that the Company used to partially finance the acquisition of Northern Utilities and Granite State which closed on December 1, 2008, and related transaction costs and expenses and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt.

Dividend Reinvestment and Stock Purchase Plan—During 2009, the Company sold 43,615 shares of its common stock, at an average price of $20.82 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $0.9 million were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's common stock and cash payments in additional shares of the Company's common stock. During 2008 and 2007, the Company raised $0.8 million and $1.0 million, respectively, of additional common equity through the issuance of 32,754 and 38,309 shares, respectively, of its common stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired—During 2009, 2008 and 2007, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. The Company accounts for its stock-based compensation plans in accordance with the provisions of the FASB Codification and recognizes compensation costs at fair value at the date of grant. Details of the plans are as follows:

Restricted Stock Plan—On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company common stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided for in the Plan. Awards fully vest over a period of four years at a rate of 25% each year.

During the vesting period, dividends on restricted shares underlying the award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit.

Restricted shares issued for 2007 – 2009 in conjunction with the Plan are presented in the following table:

Issuance Date	Shares	Aggregate Market Value (millions)
2/9/07	9,020	$0.2
2/6/08	15,540	$0.4
2/17/09	32,260	$0.7

The compensation expense associated with the issuance of shares under the Plan is being accrued over the vesting period and was $0.7 million, $0.5 million and $0.4 million in 2009, 2008 and 2007, respectively. At December 31, 2009, there was approximately $1.0 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over a weighted average of approximately 2.7 years as the shares vest. There were 32,043 and 21,024 non-vested shares under the Plan as of December 31, 2009 and 2008, respectively. The weighted average grant date fair value of these shares was $22.78 and $27.38, respectively. There were 733 restricted shares forfeited under the Plan during 2009. There were no cancellations under the Plan during 2008.

Unitil Corporation Key Employee Stock Option Plan—In the third quarter of 2007, the Company issued and sold 42,437 shares of its common stock, at a final average price of $10.70 per share, in connection with the exercise of stock options under the Unitil Corporation Key Employee Stock Option Plan (KESOP) which expired in 2007. The aggregate intrinsic value of the options exercised was $0.8 million. As of December 31, 2007, there are no options remaining under the KESOP. Net proceeds of $0.5 million were used by the Company to reduce short-term borrowings.

The total compensation expense recorded by the Company with respect to this plan was $57,000 for the year ended December 31, 2007. There was no compensation expense recorded for the years ended December 31, 2008 and 2009 with respect to this plan.

Share Option Activity of the KESOP is presented in the following table:

	2007
Beginning Options Outstanding and Exercisable	**25,000**
Dividend Equivalents Earned—Prior Years	**15,388**
Dividend Equivalents Earned—Current Year	**2,049**
Options Exercised	**(42,437)**
Ending Options Outstanding and Exercisable	**—**
Weighted Average Exercise Price per Share	**$10.70**
Range of Option Exercise Price per Share	**$12.11-$18.28**
Weighted Average Remaining Contractual Life	**n/a**

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's common stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. This plan was terminated on January 16, 2003 but will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan.

In 2008, the Company issued and sold 3,300 shares of its common stock, at a final average price of $24.51 per share, in connection with the exercise of stock options under the Unitil Corporation 1998 Stock Option Plan. The aggregate intrinsic value of the options exercised was less than $0.1 million. Net proceeds of $0.1 million were used by the Company to reduce short-term borrowings. There was no compensation expense associated with this plan in 2009, 2008 and 2007. No further grants of options will be made under this plan. As of December 31, 2009 and 2008, there was no aggregate intrinsic value of the options exercisable. As of December 31, 2007, the intrinsic value of the options exercisable was $0.1 million.

	2009		2008		2007	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Beginning Options Outstanding	**97,200**	**$27.16**	107,000	$27.13	107,000	$27.13
Options Granted	**—**	**—**	—	—	—	—
Options Exercised	**—**	**—**	(3,300)	$24.51	—	—
Options Forfeited / Expired	**(33,700)**	**$23.88**	(6,500)	$27.99	—	—
Ending Options Outstanding	**63,500**	**$28.90**	97,200	$27.16	107,000	$27.13
Options Vested and Exercisable- end of year	**63,500**	**$28.90**	97,200	$27.16	107,000	$27.13

The following summarizes certain data for the options outstanding at December 31, 2009:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$25.00-$29.99	33,000	$25.88	1.1 years
$30.00-$34.99	30,500	$32.17	0.1 years
	63,500		

Preferred Stock

Two of Unitil's distribution companies, Unitil Energy and Fitchburg, have $2.0 million of preferred stock outstanding. At December 31, 2009, Unitil Energy has $0.2 million of 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and Fitchburg has two series of Redeemable, Cumulative Preferred Stock outstanding, $0.8 million of 5.125% Series and $1.0 million of 8.00% Series.

Fitchburg is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, Fitchburg may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2009, 2008 and 2007 related to the annual redemption offer were $26,000, $21,200 and $21,700, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2009 is $117,000 per year.

Earnings Per Share

The following table reconciles basic and diluted earnings per share.

(Millions except shares and per share data)	2009	2008	2007
Earnings Available to Common Shareholders	**$ 9.9**	$ 9.6	$ 8.6
Weighted Average Common Shares Outstanding—Basic (000's)	**9,647**	5,830	5,659
Plus: Diluted Effect of Incremental Shares (000's)	**—**	—	13
Weighted Average Common Shares Outstanding—Diluted (000's)	**9,647**	5,830	5,672
Earnings per Share—Basic and Diluted	**$ 1.03**	$ 1.65	$ 1.52

Weighted average options to purchase 63,500, 97,200 and 35,000 shares of common stock were outstanding during 2009, 2008 and 2007, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Additionally, 28,963, 15,985 and 2,030 weighted average non-vested restricted shares for 2009, 2008 and 2007, respectively, were not included in the above computation because the effect would have been antidilutive.

Note 4: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowings under its revolving credit facility. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery, vehicles and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Long-Term Debt Structure and Covenants—The agreements under which the long-term debt of Unitil and its utility subsidiaries, Unitil Energy, Fitchburg, Northern Utilities, and Granite State, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

The long-term debt of Unitil is issued under Unsecured Promissory Notes with negative pledge provisions. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Unitil to issue new long-term debt, the covenants of the existing long-term agreement(s) must be satisfied, including that Unitil have total funded indebtedness less than 70% of total capitalization, and earnings available for interest equal to at least two times the interest charges for funded indebtedness. Each future senior long-term debt issuance of Unitil will rank pari passu with all other senior unsecured long-term debt issuances. The Unitil agreement requires that if Unitil defaults on any other future long-term debt agreement(s), it would constitute a default under its present long-term debt agreement. Furthermore, the default provisions are triggered by the defaults of Unitil Energy and Fitchburg or certain other actions against subsidiary companies in the Unitil System.

Substantially all of the property of Unitil Energy is subject to liens of indenture under which First Mortgage Bonds (FMB) have been issued. In order to issue new FMB, the customary covenants of the existing Unitil Energy Indenture Agreement must be met, including that Unitil Energy have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Unitil Energy agreements further require that if Unitil Energy defaults on any Unitil Energy FMB, it would constitute a default for all Unitil Energy FMB. The Unitil Energy default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

All of the long-term debt of Fitchburg, Northern Utilities and Granite State are issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of long-term debt ranks pari passu with its other senior unsecured long-term debt within that subsidiary. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Fitchburg, Northern Utilities or Granite State to issue new long-term debt, the covenants of the existing long-term agreements of that subsidiary must be satisfied, including that the subsidiary have total funded indebtedness less than 65% of total capitalization. Additionally, to issue new long-term debt, Fitchburg must maintain earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Unitil Energy agreements, the Fitchburg, Northern Utilities and Granite State agreements each require that if that subsidiary defaults on any of its own long-term debt agreements, it would constitute a default under all of that subsidiary's long-term debt agreements. Each of the Fitchburg, Northern Utilities and Granite State default provisions are not triggered by the actions or defaults of Unitil or any of its other subsidiaries.

The Unitil, Unitil Energy, Fitchburg, Northern Utilities and Granite State long-term debt instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets. The Granite State notes are guaranteed by Unitil for the payment of principal, interest and other amounts payable. This guarantee will terminate if Granite State is reorganized and merges with and into Northern Utilities.

At December 31, 2009, there were no restrictions on Unitil's Retained Earnings for the payment of common dividends. Unitil Energy, Fitchburg, Northern Utilities and Granite State pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil's common shareholders.

Debt Repayment and Sinking Funds—The total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $393,946, $363,755, and $335,877 in 2009, 2008, and 2007, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2009 is: 2010 – $426,643; 2011 – $462,055; 2012 – $500,405; 2013 – $541,938; and 2014 – $2,486,919, respectively.

Long-Term Debt Issuances

On December 18, 2009, both Unitil Energy and Northern Utilities priced long-term financings scheduled to close in the first quarter of 2010:

(i) Unitil Energy priced $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds were priced at a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Unitil Energy anticipates closing this long-term financing in March 2010.

(ii) Northern Utilities priced $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes were priced at a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Northern Utilities anticipates closing this long-term financing in March 2010.

The Unitil Energy and Northern Utilities securities offered will not be, and have not been, registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On May 2, 2007, Unitil completed the sale of $20 million of Senior Long-Term Notes, through a private placement to institutional investors. The Notes have a term of 15 years maturity and a coupon rate of 6.33%. The Company used the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries.

Fair Value of Long-Term Debt—Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements. If there were an active market for the Company's debt securities, the fair value of the Company's long-term debt would be estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield for December 2009. The carrying value of the Company's long-term debt at December 31, 2009 is $249.3 million. The fair value of the Company's long-term debt at December 31, 2009 is estimated to be approximately $271.6 million. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

Details on long-term debt at December 31, 2009 and 2008 are shown below:

	December 31,	
Long-Term Debt (millions)	**2009**	**2008**
Unitil Corporation Senior Notes:		
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0
Unitil Energy First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15.0**	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0
Fitchburg Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19.0**	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0
Northern Utilities Senior Notes:		
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	30.0
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	50.0
Granite State Senior Notes:		
7.15% Senior Notes, Due December 15, 2018	**10.0**	10.0
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**4.3**	4.7
Total Long-Term Debt	**249.3**	249.7
Less: Current Portion	**0.4**	0.4
Total Long-Term Debt, Less Current Portion	**$248.9**	$249.3

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Consistent with regulatory precedent, interest income is recorded on an under-collection of costs, including carrying charges of $1.1 million in 2009 on deferred storm costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)

	2009	2008	2007
Interest Expense			
Long-term Debt	**$18.2**	$12.0	$11.1
Short-term Debt	**2.1**	1.3	1.1
Regulatory Liabilities	**0.3**	0.1	0.8
Subtotal Interest Expense	**20.6**	13.4	13.0
Interest Income			
Regulatory Assets	**(3.6)**	(2.5)	(2.9)
AFUDC [1] and Other	**(1.2)**	(0.4)	(0.5)
Subtotal Interest Income	**(4.8)**	(2.9)	(3.4)
Total Interest Expense, net	**$15.8**	$10.5	$ 9.6

(1) AFUDC—Allowance for Funds Used During Construction

Credit Arrangements

At December 31, 2009, the Company had $64.5 million in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter. As of December 31, 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 13, 2009, the Company entered into an amendment to its 364-day revolving credit facility with Bank of America, as administrative agent, and a syndicate of lenders. The Company originally entered into the facility on November 26, 2008. The amendment increases the maximum borrowings under the facility from $60 million to $80 million. It also (i) decreases the upfront fees to 15 basis points of the aggregate commitment, (ii) changes the commitment fees from 30 to 40 basis points per annum of the average difference between the aggregate commitment and the outstanding borrowings, (iii) changes the margin applicable to borrowings from 1.75% to 2.0% per annum, and (iv) extends the maturity date for borrowings to October 12, 2010. Except as expressly amended by the amendment, all other terms and conditions of the facility remain in full force and effect.

The weighted average interest rates on all short-term borrowings were 3.4%, 3.8%, and 5.6% during 2009, 2008, and 2007, respectively.

Northern enters into asset management agreements under which Northern releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $10.0 million and $31.8 million outstanding at December 31, 2009 and December 31, 2008, respectively, related to these asset management agreements.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2009, 2008 and 2007 amounted to $1.0 million, $0.6 million and $0.4 million respectively. Fitchburg leases its operations facility in Fitchburg, Massachusetts under an operating lease, with a primary term through January 31, 2013. The lease agreement allows for three additional five-year renewal periods at the option of Fitchburg.

The following is a schedule of future operating lease payment obligations and future minimum lease payments under capital leases as of December 31, 2009:

Year Ending December 31, (000's)	Operating Leases	Capital Leases
2010	$1,027	$ 656
2011	906	568
2012	820	252
2013	467	53
2014	250	3
2015 – 2019	467	—
Total Payments	$3,937	$1,532

Guarantees

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2009, there were approximately $30.5 million of guarantees outstanding and the longest term guarantee extends through December 31, 2010. Of this amount, $8.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.3 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Note 5: Energy Supply

Natural Gas Supply

With the purchase of Northern Utilities on December 1, 2008, Unitil now manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and commercial and industrial (C&I) customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, although most of Fitchburg's customers continue to purchase such supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply at regulated rates from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

In the fourth quarter of 2009, the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus carrying charges, to its gas customers. Fitchburg recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. Fitchburg has appealed this order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Northern Utilities' service territory.

Northern has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Electric Power Supply

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third party energy suppliers. As of December 2009, 99 or 67% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 79% of Unitil's largest Massachusetts customers, representing 35% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential and small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two three-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

Prior to May 1, 2003, Unitil Energy purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, Unitil Energy and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to Unitil Energy ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, Unitil Energy continues to pay contract release payments to Unitil Power for stranded costs associated with the portfolio sale and its other ongoing power supply-related costs. In connection with the restructuring of the electric industry, Unitil Power and Fitchburg divested substantially all of their long-term power supply contracts and interests in generation assets through the sale of the interest in those assets or the sale of the entitlements to the electricity provided by those generation assets and long-term power supply contracts.

Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Note 6: Commitments and Contingencies

Legal Proceedings

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Regulatory Matters

Overview (Unitil Energy, Fitchburg, and Northern Utilities): Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territory at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next two to four years, is $63.0 million as of December 31, 2009 including $17.7 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Unitil was able to restore power to over 80 percent of its customers by day seven, and its final customers, including those with individual service problems, were restored in Massachusetts by December 24, 2008. As a result of the December 2008 Ice Storm, the Company has spent approximately $23 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.3 million related to capital construction and $14.6 million, including carrying charges, which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

On January 7, 2009, the MDPU opened an investigation into the preparation and response of the Massachusetts electric distribution companies to the December 2008 Ice Storm. Evidentiary hearings before the MDPU concerning Fitchburg's storm response were held in May, 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service. As a result, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices to address: Unitil's strategic planning processes; its staffing decisions to the extent to which they affect Fitchburg; its management and control of Fitchburg, including resource allocation decisions made among Unitil's three subsidiary companies; and customer relations. The order also directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

On July 28, 2009, Fitchburg filed with the MDPU a petition for approval to defer and record as a regulatory asset approximately $11.5 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. On December 30, 2009, the MDPU approved the request. The order of approval stated that it made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. Fitchburg anticipates filing its next rate case during the second quarter of 2010. As of December 31, 2009, Fitchburg has deferred approximately $12.3 million of costs, including carrying charges, associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On August 26, 2009, Unitil Energy filed a petition with the NHPUC requesting an accounting order authorizing Unitil Energy to record as a regulatory asset approximately $2 million in expenses associated with network damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's next base rate case. On November 9, 2009, the NHPUC granted the requested accounting order, clarifying that such issues as the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are issues that will be deferred to Unitil Energy's next rate case. Unitil Energy anticipates filing its next rate case during the second quarter 2010. As of December 31, 2009, Unitil Energy has deferred approximately $2.3 million of costs, including carrying charges, associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates.

On December 3, 2009, the NHPUC issued its final report regarding its 'after action' review of the December 2008 Ice Storm. The after action review was a non-docketed investigation by the NHPUC of utility emergency preparedness and response. The report stated that the NHPUC will commence an adjudicative proceeding to examine the reasonableness of the timing of Unitil's response to the December 2008 Ice Storm, the priorities of its restorations and the allocation of its resources in New Hampshire and Massachusetts. On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. This matter remains pending.

Unitil Energy: On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On January 16, 2009, the NHPUC issued its decision in this matter, concluding that such rate mechanisms should only be implemented on a company-by-company basis in the context of an examination of company-specific costs and revenues, service territory, customer mix and rate base investment. On March 23, 2009, the NHPUC denied a Motion for Rehearing of this matter.

In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources. This matter remains pending before the NHPUC.

Fitchburg—Electric Operations: On November 25, 2009, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery is proposed through a Transition Charge Surcharge of $0.00400 per kWh. Changes to the Pension/PBOP Adjustment and Residential Assistance Adjustment Factor were proposed in other proceedings. The rates were approved effective January 1, 2010, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2008 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting the items required by House Bill 4329.

Fitchburg—Gas Operations: Fitchburg provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDPU. Its current distribution rates were approved by the MDPU in 2007. Fitchburg's customers may purchase natural gas supplies from third-party vendors or purchase their natural gas from Fitchburg under regulated rates and tariffs. Fitchburg collects its natural gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On March 12, 2009, the MDPU opened an investigation into Fitchburg's gas procurement practices. On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg's assessment is that pre-approval from the MDPU for gas purchases made to stabilize prices for customers was not required and that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. In addition, Fitchburg is able to demonstrate that its gas purchasing practices were previously disclosed to the MDPU at public hearings and in required filings with the MDPU and the Massachusetts Office of the Attorney General. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

During the summer of 2009, Fitchburg operated its gas system entirely on local production from LNG for approximately three months due to construction on the lateral from Tennessee Gas Pipeline, which is the sole source of pipeline gas to Fitchburg. During this time Fitchburg provided gas LNG supply to all firm sales customers and also to the retail marketers for delivery to firm customers who have contracted for third party supply. Fitchburg's management of this project was reviewed by the MDPU during its last Integrated

Resource Plan proceeding, before the shutdown occurred. In its order, the MDPU stated it would investigate the costs associated with the shutdown in Fitchburg's March 2010 Cost of Gas Adjustment Clause filing when its actual costs will be reconciled with its projected costs.

Fitchburg—Other: On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, including company-specific rate cases. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012.

On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, and special tariffs to allow the net metering of customer-owned renewable generation. These matters, under review in separately designated dockets, remain pending, except for net metering tariffs which were approved by the MDPU effective December 1, 2009.

Northern Utilities: On December 1, 2008 Unitil completed the purchase of Northern Utilities from Bay State and Granite State from NiSource. Unopposed settlement agreements resolving all outstanding issues and recommending approval of the acquisition were approved by the NHPUC on October 10, 2008, and by the MPUC on November 5, 2008. Pursuant to its expanded authority over holding company mergers under the GC Act, the MDPU also reviewed the transaction and issued its approval on November 18, 2008.

The New Hampshire and Maine settlement agreements included the following provisions with respect to the accounting and rates of Northern Utilities:

- approval of Northern Utilities' accounting deferral and 10-year amortization of transaction costs and transition costs resulting from the Company's acquisition of Northern Utilities and the Company's agreement not to seek recovery of these costs, or the transaction or transition costs of any other utility subsidiary, in rates.
- agreement that synergy savings resulting from the acquisition of Northern Utilities will be retained by the Company until the next base rate change and then will flow to customers;
- agreement not to request a base rate change for Northern Utilities before November 1, 2010 unless (i) Northern Utilities' projected annual revenues are more than 8% below the level of total 2007 distribution revenues or (ii) the MPUC or NHPUC, as applicable, approves a plan to subject Granite State's rates to state regulation;
- agreement to allow Northern Utilities to recover prudently incurred integration costs for capitalized expenditures to build or upgrade systems or facilities required to independently operate Northern Utilities;
- agreement not to seek recovery in Northern Utilities' rates of any acquisition premium resulting from Unitil's acquisition of Northern Utilities and that any acquisition adjustment (positive or negative) shall be accounted for below the line for ratemaking purposes over a 10-year period;

- agreement to hold Northern Utilities' customers harmless for the elimination of historical accumulated deferred income tax (ADIT) liabilities resulting from its Internal Revenue Service Section 338(h)(10) election;
- agreement to use an imputed weighted cost of debt for ratemaking purposes until Northern Utilities' existing debt instruments would have matured; and
- agreement not to change Northern Utilities' existing depreciation rates for its Maine division until approved in the next general rate case.

The settlement agreements contained the following commitments related to Granite State:

- agreement to work collaboratively with the parties to the settlements to design and to conduct a comprehensive study of the issues and costs for modification of the physical, operational, regulatory, and corporate structure necessary for state regulation of Granite State and to provide a report within one year of the closing; and
- authorization for Northern Utilities to execute a firm service contract with Granite State for 100,000 Dekatherms (Dth) of capacity at Granite State's current recourse rate of $1.6666/ Dth for the period November 1, 2008 through October 31, 2010.

On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation ("NOPVs") of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern's distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at December 31, 2009 was $2.3 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in the Portland and Westbrook service areas. Northern Utilities anticipates filing testimony and a proposal for a replacement program with the MPUC by mid-February of 2010, and that proceedings will continue on this matter during the second and third quarters of 2010.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site not recovered by insurance or other means in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between Fitchburg and its gas customers.

Fitchburg is in the process of developing long-range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2009 and 2008 in Environmental Obligations are accrued liabilities totaling $12.0 million and $11.1 million, respectively, related to estimated future clean up costs for permanent remediation of the Sawyer Passway site. A corresponding Regulatory Asset was recorded to reflect that the recovery of this environmental remediation cost is probable through the regulatory process. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

Northern Utilities Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid 1800s through the mid 1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. Northern Utilities believes material future costs will be recovered. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Included in the Company's Consolidated Balance Sheet at December 31, 2009 and 2008 are current and non-current accrued liabilities totaling $2.5 million and $1.6 million, respectively, associated with Northern Utilities environmental remediation obligations for these former MGP sites. A corresponding Regulatory Asset was recorded to reflect that the recovery of these environmental remediation cost is probable through the regulatory process.

The Company's ultimate liability for future environmental remediation costs, including MGP site costs, may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

The following table shows the balances and activity in the Company's liability for Environmental Obligations for 2009. The liability for Environmental Obligations was initially recognized on the Company's Consolidated Balance Sheet at December 31, 2006.

ENVIRONMENTAL OBLIGATIONS

	December 31,	
(Millions)	**2009**	**2008**
Total Environmental Obligations—Balance at Beginning of Period	**$12.7**	$12.0
Changes in Estimates	**1.8**	—
Liabilities Assumed	**—**	1.6
Payments / Reductions	**—**	0.9
Total Environmental Obligations—Balance at End of Period	**14.5**	12.7
Less: Current Portion (1)	**0.2**	0.4
Environmental Obligations—noncurrent—Balance at End of Period	**$14.3**	$12.3

(1) Reflects amounts included in Other Current Liabilities on the Company's Consolidated Balance Sheets.

Note 7: Bad Debts

Unitil's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. In 2009, 2008 and 2007, the Company recorded provisions for the energy commodity portion of bad debts of $1.9 million, $2.1 million and $1.5 million, respectively. These provisions were recognized in Purchased Electricity and Purchased Gas expense as the associated electric and gas utility revenues were billed. Purchased Electricity and Purchased Gas costs are recovered from customers through periodic rate reconciling mechanisms.

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2007 – 2009 ($ millions):

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	(a) Other	Provision	Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2009						
Electric	**$1.1**	**$ —**	**$2.3**	**$0.2**	**$1.9**	**$1.7**
Gas	**1.8**	**0.5**	**1.4**	**0.3**	**3.3**	**0.7**
Other	**0.1**	**—**	**—**	**—**	**—**	**0.1**
	$3.0	**$0.5**	**$3.7**	**$0.5**	**$5.2**	**$2.5**
Year Ended December 31, 2008						
Electric	$1.0	$ —	$2.2	$0.2	$2.3	$1.1
Gas	0.2	1.4	1.4	0.2	1.4	1.8
Other	0.1	—	—	—	—	0.1
	$1.3	$1.4	$3.6	$0.4	$3.7	$3.0
Year Ended December 31, 2007						
Electric	$1.2	$ —	$1.4	$0.2	$1.8	$1.0
Gas	0.4	—	1.0	0.1	1.3	0.2
Other	0.1	—	—	—	—	0.1
	$1.7	$ —	$2.4	$0.3	$3.1	$1.3

(a) Includes Allowance for Doubtful Accounts of Northern Utilities and Granite State, which were acquired on December 1, 2008.

Note 8: Income Taxes

Federal Income Taxes were provided for the following items for the years ended December 31, 2009, 2008 and 2007, respectively:

	2009	2008	2007
Current Federal Tax Provision (Benefit) (000's):			
Operating Income	**$(3,226)**	$(2,914)	$4,522
Total Current Federal Tax Provision (Benefit)	**(3,226)**	(2,914)	4,522
Deferred Federal Tax Provision (Benefit) (000's)			
Accelerated Tax Depreciation	**8,716**	5,159	(444)
Regulatory Assets and Liabilities	**(1,308)**	1,534	(400)
Other, net	**(120)**	121	60
Total Deferred Federal Tax Provision (Benefit)	**7,288**	6,814	(784)
Total Federal Tax Provision	**$ 4,062**	$ 3,900	$3,738

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2009, 2008 and 2007 are shown in the table below. In addition to the provisions for federal and state income taxes, the Company recorded provisions of $202,000, $165,000 and $203,000 in 2009, 2008 and 2007, respectively for New Hampshire Business Enterprise taxes, which are included in Local Property and Other Taxes on the consolidated statements of earnings.

Federal and State Tax Provision (Benefit) (000's)	2009	2008	2007
Federal			
Current	**$(3,226)**	$(2,914)	$4,522
Deferred	**7,288**	6,814	(784)
Total Federal Tax Provision	**4,062**	3,900	3,738
State			
Current	**1,376**	(42)	896
Deferred	**(218)**	592	(138)
Total State Tax Provision	**1,158**	550	758
Total Provision for Federal and State Income Taxes	**$ 5,220**	$ 4,450	$4,496

The differences between the Company's provisions for Income Taxes, including the provision for Business Enterprise taxes, and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2009	2008	2007
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**6**	5	5
Utility Plant Differences	**(3)**	(6)	(4)
Other, Net	**(1)**	(1)	—
Effective Income Tax Rate	**36%**	32%	35%

Temporary differences, including the effect of deferred tax accounting on the assets and liabilities of Northern Utilities and Granite State acquired on December 1, 2008 (see Note 2 above), which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	2009	2008
Depreciation and Utility Plant	**$ 30,318**	$ 22,611
Regulatory Assets / Liabilities & Mechanisms	**29,094**	30,071
Retirement Benefit Obligations	**(22,537)**	(23,029)
Other, net	**2,896**	1,431
Total Deferred Income Tax Liabilities	**$ 39,771**	$ 31,084

The Company evaluated its tax positions at December 31, 2009 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by the FASB Codification is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2006; December 31, 2007; and December 31, 2008. Income tax filings for the year ended December 31, 2008 have been filed with the Internal Revenue Service (IRS). In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized net operating loss (NOL) carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of $5.0 million and $6.7 million, respectively. These NOL carrybacks resulted in a refund to the Company of $4.0 million which was received in November 2009. According to Internal Revenue Code rules, NOL refunds in excess of $2.0 million fall under the jurisdiction of the Joint

Committee of Congress (Joint Committee) and are subject to review by the IRS and attorneys of the Joint Committee. As a result, on December 30, 2009, the Company received notice that its Federal Income Tax return filings for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 are under examination by the IRS. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Note 9: Retirement Benefit Plans

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan)—The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service. In September 2009, the Company amended the Pension Plan as follows:
  - The Pension Plan will be closed to non-union employees who are hired on or after January 1, 2010.
  - All non-union employees hired before January 1, 2010 will have a choice of either:
    - Remaining in the Pension Plan with the current set of benefits.

    or

    - Electing to move to Unitil Corporation's enhanced Tax Deferred Savings and Investment Plan. Non-union employees who elect this option will receive a frozen benefit from the existing Pension Plan for all of the benefits that they have accrued to December 31, 2008. This frozen benefit will not grow with future salary increases or future service. Non-union employees who elect this option will receive an enhanced employer matching contribution as well as a Company contribution in the Unitil Corporation Tax Deferred Savings and Investment Plan.
    - Union employees were not affected by this amendment.
- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan)—The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan. In 2009, the Company made the following changes to the PBOP Plan.

  Changes to Utility Workers Union of America Local 341 Benefits

  A new Collective Bargaining Agreement ("Agreement") was entered into between Northern Utilities, Inc., Granite State Gas Transmission, Inc. and Utility Workers Union of America Local 341 ("UWUA") for the period April 1, 2009 through March 31, 2012. Included in the Agreement were changes to retiree medical benefits under the Plan. These changes are as follows:

    - Retirees under sixty-five (65) years and their dependents will be covered by the medical benefits provided by the PBOP Plan. Early retirees will be responsible for contributing 20% of the premium for medical insurance for themselves and their dependents until age sixty-five (65).
    - Retirees over sixty-five (65) years will be covered by a Supplement to Medicare Plan and will be responsible for a 20% premium cost sharing.
    - For all employees hired on or after April 1, 2009, no post-65 retiree medical coverage will be provided.
    - The Company is to determine post-65 drug coverage to be offered to all future retirees eligible for retiree medical.

  These above-referenced retiree medical provisions were effective January 1, 2010.

Changes to Non-Union Employee Benefits

In September 2009, the Company announced the following PBOP Plan changes, effective January 1, 2010, for non-union employees:

- Employees who retire on or after January 1, 2010 will pay 20% of the cost of their retiree medical benefits.
- Employees who retire on or after January 1, 2010 will not receive any cash payments towards their Medicare premiums.
- Employees who are hired on or after January 1, 2010 will only be provided with company subsidized medical insurance until they reach age 65 and will not receive a Medicare supplement plan after age 65.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP)—The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

Effective with the acquisitions of Northern Utilities and Granite State, the Company assumed the assets and obligations of the Northern Utilities and Granite State pension plans with respect to active union employees. All other active employees of Northern Utilities and Granite State effectively became members of the Company's Pension Plan as of the acquisitions closing date.

Certain employees of Northern Utilities qualified for participation in the Company's PBOP Plan effective with the acquisition closing date.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan costs for years ended December 31:	2009	2008	2007
Discount Rate [1]	**6.25%**	6.00%	5.50%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	8.50%	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017	2016
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 735**	$ 675	$ 690
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$ (576)**	$ (531)	$ (539)

[1] As a result of the changes to the PBOP Plan in September 2009 discussed above, the Company was required to update the discount rate used in determining the PBOP Plan costs for the remainder of 2009. Based on the market rates for long-term bonds at that time, the Company assumed a discount rate of 5.50% for the PBOP Plan from September through December of 2009.

Used to Determine Benefit Obligations at December 31:			
Discount Rate	**5.75%**	6.25%	6.00%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.50%**	8.00%	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2017	2017
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 5,887**	$ 6,084	$ 6,282
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$(4,704)**	$(4,890)	$(5,030)

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2009, 2008 and 2007, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000, $200,000 and $200,000, respectively, in the Net Periodic Benefit Cost (NPBC). The Rate of Compensation Increase assumption used for 2009, 2008 and 2007 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan			PBOP Plan			SERP		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Service Cost	**$ 2,282**	$ 1,979	$ 1,968	**$ 1,417**	$ 1,447	$ 1,431	**$217**	$150	$163
Interest Cost	**4,294**	3,800	3,336	**2,269**	2,212	2,057	**182**	126	118
Expected Return on Plan Assets	**(4,432)**	(4,390)	(4,195)	**(440)**	(325)	(245)	**—**	—	—
Prior Service Cost Amortization	**264**	119	106	**1,634**	1,390	1,360	**(2)**	(1)	(2)
Transition Obligation Amortization	**—**	—	—	**21**	21	21	**—**	—	—
Curtailment Loss	**32**	—	—	**—**	—	—	**—**	—	—
Actuarial Loss Amortization	**1,598**	1,274	1,345	**—**	—	70	**70**	24	44
Sub-total	4,038	2,782	2,560	4,901	4,745	4,694	467	299	323
Amounts Capitalized and Deferred	**(1,409)**	(893)	(873)	**(1,642)**	(1,872)	(2,033)	**—**	—	—
NPBC Recognized	**$ 2,629**	$ 1,889	$ 1,687	**$ 3,259**	$ 2,873	$ 2,661	**$467**	$299	$323

The estimated amortizations related to Actuarial Loss and Prior Service Cost included in the Company's Retirement plan costs over the next fiscal year is $2.7 million, $1.6 million and $0.1 million for the Pension, PBOP and SERP plans, respectively.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2009, 2008 and 2007 before capitalization and deferral was $4.0 million, $2.8 million and $2.6 million, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2009, 2008 and 2007 would have been $6.3 million, $2.9 million and $2.5 million respectively.

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan		PBOP Plan		SERP	
Change in Plan Assets:	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**
Plan Assets at Beginning of Year	**$ 39,124**	$ 52,162	**$ 4,361**	$ 4,144	**$ —**	$ —
Actual Return on Plan Assets	**8,017**	(15,542)	**874**	(784)	**—**	—
Employer Contributions	**4,227**	2,800	**2,800**	2,700	**53**	59
Participant Contributions	**—**	—	**2**	—	**—**	—
Acquired Plan Assets	**(544)**	2,500	**—**	—	**—**	—
Benefits Paid	**(3,742)**	(2,796)	**(1,731)**	(1,699)	**(53)**	(59)
Plan Assets at End of Year	**$ 47,082**	$ 39,124	**$ 6,306**	$ 4,361	**$ —**	$ —
Change in PBO:						
PBO at Beginning of Year	**$ 70,386**	$ 64,429	**$ 37,655**	$ 37,983	**$ 2,930**	$ 2,144
Service Cost	**2,282**	1,979	**1,417**	1,447	**217**	150
Interest Cost	**4,294**	3,800	**2,269**	2,212	**182**	126
Participant Contributions	**—**	—	**2**	—	**—**	—
Plan Amendments	**—**	—	**(2,382)**	—	**—**	—
Estimated Acquired Obligations	**—**	4,442	**—**	2,610	**—**	—
Curtailment Gain	**(599)**	—	**—**	—	**—**	—
Benefits Paid	**(3,742)**	(2,796)	**(1,731)**	(1,699)	**(53)**	(59)
Actuarial (Gain) or Loss	**6,667**	(1,468)	**(1,536)**	(4,898)	**703**	569
PBO at End of Year	**$ 79,288**	$ 70,386	**$ 35,694**	$ 37,655	**$ 3,979**	$ 2,930
Funded Status: Assets vs PBO	**$(32,206)**	$(31,262)	**$(29,388)**	$(33,294)	**$(3,979)**	$(2,930)

The Company has recorded on its balance sheets as a liability the underfunded status of their retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets of $43.7 million and $45.5 million at December 31, 2009 and 2008, respectively, to recognize the future collection of these plan obligations in electric and gas rates.

The Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $69.0 million and $61.1 million as of December 31, 2009 and 2008, respectively. The ABO for the SERP was $0.5 million and $0.5 million as of December 31, 2009 and 2008, respectively. For the PBOP Plan, the ABO and PBO are the same.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in

the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 – 2010 plan years. This did not affect the Company's Pension Plan in 2009 as its Pension Plan was 94% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2009 and met the exemption from the shortfall amortization. The Company expects to contribute approximately $4.0 million to fund its Pension Plan in 2010.

The following table represents employer contributions and benefit payments ($000's). There were no participant contributions.

	Pension Plan			PBOP Plan			SERP		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Employer Contributions	**$4,227**	$2,800	$2,800	**$2,800**	$2,700	$2,500	**$53**	$59	$72
Benefit Payments	**$3,742**	$2,796	$2,645	**$1,731**	$1,699	$1,497	**$53**	$59	$72

The following table represents estimated future benefit payments ($000's).

	Estimated Future Benefit Payments		
	Pension	PBOP	SERP
2010	$ 3,585	$ 1,309	$ 52
2011	3,685	1,431	51
2012	3,906	1,526	50
2013	4,138	1,610	363
2014	4,376	1,725	362
2015 - 2019	$25,369	$10,047	$1,782

The Expected Long-Term Rate of Return on Pension Plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on Pension Plan assets is based on target investment allocation of 57% in common stock equities and 43% in fixed income securities. The Company's Expected Long-Term Rate of Return on PBOP Plan assets is based on target investment allocation of 55% in common stock equities and 45% in fixed income securities. The actual investment allocations are shown in the tables below.

Pension Plan	Target Allocation 2010	Actual Allocation at December 31, 2009	2008	2007
Equity Securities	57%	**59%**	54%	57%
Debt Securities	43%	**40%**	35%	43%
Other	0%	**1%**	11%	0%
Total		**100%**	100%	100%

PBOP Plan	Target Allocation 2010	Actual Allocation at December 31, 2009	2008	2007
Equity Securities	55%	**56%**	56%	0%
Debt Securities	45%	**44%**	44%	0%
Other [(1)]	0%	**0%**	0%	100%
Total		**100%**	100%	100%

(1) Represents investments in Money Market Funds.

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2009. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 5 – 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The FASB Codification defines fair value, and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under the FASB Codfiication are described below:

Level 1 – Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3 – Prices or valuations that require inputs that are both significant to the fair value measurement and unobservable.

To the extent that valuation is based on models or inputs that are less observable or unobservable in the market, the determination of fair value requires more judgment. Accordingly, the degree of judgment exercised by the Company in determining fair value is greatest for instruments categorized in Level 3. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Fair value is a market-based measure considered from the perspective of a market participant rather than an entity-specific measure. Therefore, even when market assumptions are not readily available, the Company's own assumptions are set to reflect those that market participants would use in pricing the asset or liability at the measurement date. The Company uses prices and inputs that are current as of the measurement date, including during periods of market dislocation. In periods of market dislocation, the observability of prices and inputs may be reduced for many instruments. This condition could cause an instrument to be reclassified from Level 1 to Level 2 or from Level 2 to Level 3.

Valuation Techniques

There have been no changes in the valuation techniques used during the current period.

Assets measured at fair value on a recurring basis for the Pension Plan as of December 31, 2009 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Pension Plan Assets:				
Trading Securities	**$46,667**	$46,667	$—	$—
Escrow	**415**	415		
Total Assets	**$47,082**	$47,082	$—	$—

Assets measured at fair value on a recurring basis for the PBOP Plan as of December 31, 2009 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
PBOP Plan Assets:				
Trading Securities	**$6,306**	$6,306	$—	$—
Total Assets	**$6,306**	$6,306	$—	$—

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company common stock fund.

In September 2009, the Company amended the Plan as follows:

For current non-union employees who elect to stay with the Company's existing Pension Plan, there will be no changes in the 401(k) Plan. For those employees, the Company will continue to match contributions, with a maximum matching contribution of 3% of current compensation and those participants will be 100% vested in these company matching contributions once they have completed three years of service.

For non-union employees who are hired on or after January 1, 2010, and for non-union employees who elect to move from the Company's existing Pension Plan and accept a frozen pension benefit, the Company will provide the following enhancements to the 401(k) Plan:

- The Company will contribute 4% of base pay each year, regardless of whether or not the non-union employee elects to contribute to the 401(k) Plan.
- The Company will increase the matching contributions from 3% of base pay to 6% of base pay. This will be a 100% match of the first 6% of the non-union employee's contributions.
- All Company contributions will be 100% vested at all times.
- New non-union employees will be automatically enrolled in the 401(k) Plan following the completion of 1,000 hours of service, with the automatic employee contribution rate of 3%. This contribution rate will automatically increase by 1% on January 1st of each year until the non-union employee's contribution is 10% of pay. Non-union employees may elect to opt-out of the automatic enrollment and/or automatic increase features of the enhanced 401(k) Plan.

The Company's share of contributions to the 401(k) Plan was $671,000, $542,000 and $533,000 for the years ended December 31, 2009, 2008, and 2007, respectively.

Note 10: Segment Information

Unitil reports four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine.

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transmission services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty, Unitil Service and the holding company are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries' use. Unitil Resources and Usource are included in the Non-Regulated column below.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes and preferred stock dividends. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on cost allocation factors included in rate applications approved by the NHPUC, MDPU, and MPUC. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2009, 2008 and 2007 (Millions):

Year Ended December 31, 2009	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$209.9**	**$152.8**	**$ —**	**$ 4.3**	**$367.0**
Interest Income	**3.6**	**0.5**	**0.7**	**—**	**4.8**
Interest Expense	**9.1**	**9.7**	**1.8**	**—**	**20.6**
Depreciation & Amortization Expense	**14.0**	**12.8**	**0.6**	**—**	**27.4**
Income Tax Expense (Benefit)	**2.4**	**1.9**	**(0.1)**	**1.0**	**5.2**
Segment Profit (Loss)	**4.9**	**3.3**	**0.1**	**1.6**	**9.9**
Segment Assets	**347.9**	**367.4**	**7.3**	**2.6**	**725.2**
Capital Expenditures	**27.7**	**30.0**	**1.0**	**—**	**58.7**
Year Ended December 31, 2008					
Revenues	$227.5	$ 56.9	$ —	$ 3.8	$288.2
Interest Income	2.2	0.1	0.3	—	2.6
Interest Expense	8.7	2.3	2.1	—	13.1
Depreciation & Amortization Expense	13.1	5.2	0.8	—	19.1
Income Tax Expense (Benefit)	1.9	2.6	(0.3)	0.2	4.4
Segment Profit (Loss)	5.2	4.3	(0.2)	0.3	9.6
Segment Assets	359.2	363.9	9.1	1.0	733.2
Capital Expenditures	19.7	7.6	1.0	—	28.3
Year Ended December 31, 2007					
Revenues	$225.0	$ 34.2	$ —	$ 3.7	$262.9
Interest Income	2.8	0.1	0.5	—	3.4
Interest Expense	9.6	2.1	1.3	—	13.0
Depreciation & Amortization Expense	12.6	3.8	1.3	0.1	17.8
Income Tax Expense (Benefit)	3.8	0.4	0.1	0.2	4.5
Segment Profit (Loss)	7.3	1.0	—	0.3	8.6
Segment Assets	351.9	110.3	11.7	0.7	474.6
Capital Expenditures	26.2	6.1	0.2	—	32.5

Note 11: Quarterly Financial Information (unaudited; Millions, except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding and the impact of additional commons share issuances. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2009	2008	2009	2008	2009	2008	2009	2008
Total Operating Revenues	**$135.6**	$ 71.9	**$ 71.5**	$ 59.4	**$ 70.4**	$ 69.1	**$ 89.5**	$ 87.8
Operating Income	**$ 13.9**	$ 6.0	**$ 4.2**	$ 4.2	**$ 3.4**	$ 3.9	**$ 4.6**	$ 6.4
Net Income (Loss) Applicable to Common	**$ 9.1**	$ 3.3	**$ 0.2**	$ 1.6	**$ (0.6)**	$ 1.5	**$ 1.2**	$ 3.2
	Per Share Data:							
Earnings Per Common Share	**$ 1.14**	$ 0.57	**$ 0.03**	$ 0.28	**$ (0.06)**	$ 0.27	**$ 0.11**	$ 0.53
Dividends Paid Per Common Share	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345

Note 12: Unaudited Pro Forma Financial Data Related To Acquisitions

On December 1, 2008, the Company acquired Northern Utilities and Granite State, as discussed in Note 2. Had the results of operations for Northern Utilities and Granite State been combined with the Company as of the beginning of 2007, the Company's pro forma results for 2008 and 2007 would have been as follows:

	Year ended December 31,	
(Millions, except per share amounts) (Unaudited)	2008	2007
Revenues	**$395.5**	$396.2
Earnings Applicable to Common Shareholders	**$ 8.3**	$ 11.5
Earnings per Share		
Basic	**$ 0.77**	$ 1.08
Diluted	**$ 0.77**	$ 1.08

The Unaudited Pro Forma Financial Data includes non-recurring charges to operating expenses of $1.7 million, after tax, related to compliance violation penalties incurred by Northern Utilities in 2007 and $2.5 million, after tax, related to compliance violation penalties incurred by Northern Utilities in 2008.

The Unaudited Pro Forma Financial Data are presented for illustrative purposes only and do not indicate the financial results of the combined companies had the companies actually been combined and had the impact of possible revenue enhancements and expense efficiencies, among other factors, been considered, and is not intended to be a projection of future results.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of December 31, 2009. Based upon this evaluation, the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded as of December 31, 2008 that the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) are effective.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). In addition, management is required to report their assessment, including their evaluation criteria, on the design and operating effectiveness of the Company's internal control over financial reporting in this Form 10-K.

The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The Company's internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles. The Company's internal control over financial reporting includes policies and procedures which provide reasonable assurances that transactions are properly initiated, authorized, recorded, reported and disclosed, and provide reasonable assurances regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

During 2009, management conducted an assessment of the Company's internal control over financial reporting reflected in the financial statements, based upon criteria established in the "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Based on management's assessment, which included a comprehensive review of the design and operating effectiveness of the Company's internal control over financial reporting, management believes the Company's internal control over financial reporting is designed and operating effectively as of December 31, 2009.

The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by Caturano and Company, an independent registered public accounting firm. Their report appears in Item 8.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

On December 18, 2009, both Unitil Energy and Northern Utilities priced long-term financings scheduled to close in the first quarter of 2010:

(iii) Unitil Energy priced $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds were priced at a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Unitil Energy anticipates closing this long-term financing in March 2010.

(iv) Northern Utilities priced $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes were priced at a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities plans to use the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes. Northern Utilities anticipates closing this long-term financing in March 2010.

The Unitil Energy and Northern Utilities securities offered will not be, and have not been, registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Compensation Discussion and Analysis" and "Compensation of Named Executive Officers" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the "Beneficial Ownership" and "As to the Election of Directors" sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010, as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this Item is set forth in the "Transactions with Related Persons" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2010.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2009 and 2008
- Consolidated Statements of Earnings for the years ended December 31, 2009, 2008, and 2007
- Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008, and 2007
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2009, 2008, and 2007
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	Articles of Amendment to the Articles of Incorporation Filed on September 23, 2008.	Exhibit 3.3 to Form S-3/A dated November 25, 2008
3.4	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.5	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.6	Articles of Exchange of CECo, E&H, and the Company - Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.7	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (Fitchburg) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.8	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989

Exhibit Number	Description of Exhibit	Reference*
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002
4.2	Fitchburg Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.3	Fitchburg Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.4	Fitchburg Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.5	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.6	Fitchburg Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.7	Fitchburg Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
4.8	Thirteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of September 26, 2006.	**
4.9	Unitil Corporation Note Purchase Agreement, dated as of May 2, 2007, for the 6.33% Senior Notes due May 1, 2022.	**
4.10	Northern Utilities Note Purchase Agreement, dated as of December 3, 2008, for the 6.95% Senior Notes, Series A due December 3, 2018 and the 7.72% Senior Notes, Series B due December 3, 2038.	Exhibit 4.1 to Form 8-K dated December 3, 2008
4.11	Granite State Note Purchase Agreement, dated as of December 15, 2008, for the 7.15% Senior Notes due December 15, 2018	Exhibit 99.1 to Form 8-K dated December 15, 2008
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 8-K dated June 19, 2008
10.5***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.3 to Form 8-K dated June 19, 2008
10.6***	Amended and Restated Unitil Corporation Supplemental Executive Retirement Plan effective as of December 31, 2007.	Exhibit 10.4 to Form 8-K dated June 19, 2008

Exhibit Number	Description of Exhibit	Reference*
10.7***	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.8***	Amended and Restated Unitil Corporation Management Incentive Plan effective as of June 19, 2008 as further amended on December 1, 2008.	Exhibit 10.8 to Form 10-K for 2008
10.9	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.10***	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.11	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.12	Unitil Corporation Tax Deferred Savings and Investment Plan—Trust Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2004
10.13***	Amended and Restated Employment Agreement effective as of November 1, 2009 by and between Unitil Corporation and Robert G. Schoenberger.	Exhibit 10.1 to Form 8-K dated September 23, 2009
10.14	Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated November 26, 2008
10.15	Amendment Agreement dated as of January 2, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated January 2, 2009
10.16	Amendment Agreement dated as of October 13, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008	Exhibit 10.1 to Form 8-K dated October 13, 2009
10.17	Credit Agreement between Unitil Corporation and Royal Bank of Canada dated December 1, 2008	Exhibit 10.2 to Form 8-K dated November 26, 2008
10.18	Transition Services Agreement between Unitil Corporation and NiSource, Inc. dated December 1, 2008	Exhibit 10.3 to Form 8-K dated November 26, 2008
10.19	Parent Guaranty of Unitil Corporation for the Granite State 7.15% Senior Notes due December 15, 2018	Exhibit 10.1 to Form 8-K dated December 15, 2008
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith

Exhibit Number	Description of Exhibit	Reference*
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** In accordance with Item 601(b)(4)(iii)(A) of Federal Securities Regulation S-K, the instrument defining the debt of the Registrant and its subsidiary, described above, has been omitted but will be furnished to the Commission upon request.

*** These exhibits represent a management contract or compensatory plan.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 10, 2010

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board of Directors,
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 10, 2010
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 10, 2010
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	February 10, 2010
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 10, 2010
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 10, 2010
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 10, 2010
/s/ WILLIAM D. ADAMS **William D. Adams**	Director	February 10, 2010
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 10, 2010
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 10, 2010
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 10, 2010
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 10, 2010
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 10, 2010
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	February 10, 2010

EXHIBIT INDEX

Exhibit No.	Description
11.1	Computation in Support of Earnings per Share
12.1	Computation in Support of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Registrant
23.1	Consent of Independent Registered Public Accounting Firm
31.1-31.3	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2009	2008	2007
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$10,049**	$9,735	$8,746
Less: Dividend Requirements on Preferred Stock	**134**	135	136
Net Income Applicable to Common Stock	**$ 9,915**	$9,600	$8,610
Average Number of Common Shares Outstanding—Basic	**9,647**	5,830	5,659
Dilutive Effect of Stock Options and Restricted Stock	**—**	—	13
Average Number of Common Shares Outstanding—Diluted	**9,647**	5,830	5,672
Earnings Per Share—Basic	**$ 1.03**	$ 1.65	$ 1.52
Earnings Per Share—Diluted	**$ 1.03**	$ 1.65	$ 1.52

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2009	2008	2007	2006	2005
(000's, except ratios)					
Earnings:					
Net Income, per Consolidated Statements of Earnings	**$10,049**	$ 9,735	$ 8,746	$ 8,033	$ 8,553
Federal and State Income Taxes included in Operations	**5,220**	4,450	4,482	4,266	4,275
Interest on Long-Term Debt	**17,961**	11,795	10,919	9,404	8,319
Amortization of Debt Discount Expense	**233**	151	136	112	104
Other Interest	**2,474**	1,156	1,949	1,675	1,046
Total	**$35,937**	$27,287	$26,232	$23,490	$22,297
Fixed Charges:					
Interest on Long-Term Debt	**$17,961**	$11,795	$10,919	$ 9,404	$ 8,319
Amortization of Debt Discount Expense	**233**	151	136	112	104
Other Interest	**2,474**	1,156	1,949	1,675	1,046
Pre-tax Preferred Stock Dividend Requirements	**208**	199	213	208	234
Total	**$20,876**	$13,301	$13,217	$11,399	$ 9,703
Ratio of Earnings to Fixed Charges	**1.72**	2.05	1.98	2.06	2.30

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has eight wholly-owned subsidiaries, seven of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Northern Utilities, Inc., Granite State Gas Transmission, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The eighth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements of Unitil Corporation and subsidiaries on Form S-3 (File No. 333-158537 effective April 29, 2009), Form S-3 (File No. 333-152823 effective December 5, 2008), Form S-8 (File No. 333-114978 effective April 29, 2004), Form S-3 (File No. 333-42264 effective July 26, 2000) and on Form S-8 (File No. 333-42266 effective July 26, 2000) of our report dated February 10, 2010, relating to the consolidated financial statements of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and 2008 and the three years ending December 31, 2009 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, appearing in the Annual Report of the Company on Form 10-K for the year ended December 31, 2009.

Caturano and Company P.C.

Boston, Massachusetts
February 10, 2010

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2010

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2010

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2010

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 10, 2010
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 10, 2010
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 10, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire **(State or other jurisdiction of incorporation or organization)**	**02-0381573** **(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire **(Address of principal executive offices)**	**03842-1720** **(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Based on the closing price of June 30, 2010, the aggregate market value of common stock held by non-affiliates of the registrant was $224,000,571.

The number of common shares outstanding of the registrant was 10,891,621 as of February 1, 2011.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011 are incorporated by reference into Part III of this Report

UNITIL CORPORATION
FORM 10-K
For the Fiscal Year Ended December 31, 2010
Table of Contents

PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil was incorporated under the laws of the State of New Hampshire in 1984. The following companies are wholly-owned subsidiaries of Unitil:

Company Name	State and Year of Organization	Principal Business
Unitil Energy Systems, Inc. (Unitil Energy)	NH - 1901	Electric Distribution Utility
Fitchburg Gas and Electric Light Company (Fitchburg)	MA - 1852	Electric & Gas Distribution Utility
Northern Utilities, Inc. (Northern Utilities)	NH - 1979	Natural Gas Distribution Utility
Granite State Gas Transmission, Inc. (Granite State)	NH - 1955	Natural Gas Transmission Pipeline
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-regulated Energy Services
Usource Inc. and Usource L.L.C. (Usource)	DE - 2000	Energy Brokering Services

Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territories in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities: i) Unitil Energy, which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the capital city of Concord, ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts, and iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland, which is the largest city in northern New England. In addition, Unitil is the parent company of Granite State, an interstate natural gas transmission pipeline company that provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory. Together, Unitil's three distribution utilities serve approximately 100,900 electric customers and 70,800 natural gas customers.

Unitil's distribution utilities had an investment in Net Utility Plant of $476.5 million at December 31, 2010. Unitil's total operating revenue was $358.4 million in 2010. Substantially all of Unitil's operating revenue is derived from regulated distribution utility operations.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy in 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are indirect subsidiaries that are wholly-owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers primarily in the northeastern United States.

OPERATIONS

Gas Operations

Unitil's Gas Operations include gas distribution utility operations and interstate gas transmission pipeline operations, discussed below. Revenue from Unitil's gas operations was $150.1 million for 2010, which represent about 42% of Unitil's total operating revenue. In 2008, the Company significantly expanded its gas operations by acquiring Northern Utilities and Granite State.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate natural gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement (the Acquisitions). Bay State is a wholly-owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt (see "Liquidity, Commitments and Capital Requirements" section in Part II, Item 7 below). The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features (See Note 6 to the accompanying Consolidated Financial Statements for additional information on these settlement agreements).

Gas Distribution Utility Operations

Unitil's natural gas distribution operations are conducted through two of the Company's operating utilities, Northern Utilities and Fitchburg. The primary business of Unitil's natural gas utility operations is the local distribution of natural gas to customers in its service territory in New Hampshire, Massachusetts and Maine. As a result of a restructuring of the gas utility industry in New Hampshire, Massachusetts and Maine, Fitchburg's residential and commercial and industrial (C&I) customers and Northern Utilities' C&I customers have the opportunity to purchase their natural gas supplies from third-party energy supply vendors. Most customers, however, continue to purchase such supplies through Northern Utilities and Fitchburg under regulated rates and tariffs. Northern Utilities and Fitchburg purchase natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis through reconciling rate mechanisms that are periodically adjusted.

Natural gas is supplied and distributed by Northern Utilities to approximately 55,500 customers in 44 New Hampshire and southern Maine communities, from Plaistow, New Hampshire in the south to the city of Portland, Maine and then extending to Lewiston-Auburn, Maine in the north. Northern Utilities has a diversified customer base both in Maine and New Hampshire. Commercial businesses include healthcare, education, government and retail. Northern Utilities' industrial base includes manufacturers in the industries of auto, housing, rubber, printing, textile, pharmaceutical, electronics, wires and food production as well as a military installation. Northern Utilities' 2010 gas operating revenue was $116.2 million, of which approximately 39.0% was derived from residential firm sales and 61.0% from commercial/industrial firm sales.

Natural gas is supplied and distributed by Fitchburg to approximately 15,300 customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. Fitchburg's 2010 gas operating revenue was $29.9 million, of which approximately 51% was derived from residential firm sales and 49.0% from commercial/industrial firm sales.

Gas Transmission Pipeline Operations

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State

provides Northern Utilities with interconnection to major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State had operating revenue of $4.0 million for 2010. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and to third-party marketers.

Electric Distribution Utility Operations

Unitil's electric distribution operations are conducted through two of the Company's utilities, Unitil Energy and Fitchburg. Revenue from Unitil's electric utility operations was $203.7 million for 2010, which represents about 57% of Unitil's total operating revenue.

The primary business of Unitil's electric utility operations is the local distribution of electricity to customers in its service territory in New Hampshire and Massachusetts. As a result of the implementation of choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The distribution utilities continue to deliver that supply of electricity over their distribution systems. Both Unitil Energy and Fitchburg supply electricity to those customers who do not obtain their supply from third-party suppliers, with the approved costs associated with electricity supplied by the distribution utilities being recovered on a pass-through basis under periodically-adjusted rates.

Unitil Energy distributes electricity to approximately 72,700 customers in New Hampshire in the capital city of Concord as well as parts of 12 surrounding towns and all or part of 18 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. Unitil Energy's service territory consists of approximately 408 square miles. In addition, Unitil Energy's service territory encompasses retail trading and recreation centers for the central and southeastern parts and includes the Hampton Beach recreational area. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics, healthcare and education. Unitil Energy's 2010 electric operating revenue was $140.7 million, of which approximately 54.0% was derived from residential sales and 46.0% from commercial/industrial sales.

Fitchburg is engaged in the distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts. Fitchburg's service territory encompasses approximately 170 square miles. Electricity is supplied and distributed by Fitchburg to approximately 28,200 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. Fitchburg's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries and education. Fitchburg's 2010 electric operating revenue was $63.0 million, of which approximately 53.0% was derived from residential sales and 47.0% from commercial/industrial sales.

Seasonality

As a result of the acquisitions of Northern Utilities and Granite State in 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in all reporting periods presented. In particular, the Company's results will reflect the seasonal nature of the natural gas distribution business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher due to heating-related requirements, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer months due to air conditioning demand and the winter months due to heating-related requirements and shorter daylight hours. Unitil Energy, Fitchburg and Northern Utilities are not dependent on a single customer or a few customers for their electric and natural gas sales.

Non-regulated and Other Non-Utility Operations

Unitil's non-regulated operations are conducted through Usource, a subsidiary of Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's non-regulated operations was $4.6 million in 2010.

The results of Unitil's other non-utility subsidiaries, Unitil Service and Unitil Realty, and the holding company are included in the Company's consolidated results of operations. The results of these non-utility operations are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and are reported, after intercompany eliminations, in Other segment income (for segment information, see Part II, Item 8, Note 9 herein).

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 with regard to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, with regard to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and Maine Public Utilities Commission (MPUC). Granite State, Unitil's interstate natural gas transmission pipeline, is subject to regulation by the FERC with regard to its rates and operations. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third-party energy supply vendors. Most customers, however, continue to purchase such supplies through the distribution utilities under regulated energy rates and tariffs. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual approved costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

Rate Case Activity

On April 15, 2010, Unitil Energy filed for a distribution base rate increase of $10.1 million. The Company's filing also included a proposed long-term rate plan establishing step adjustments for future utility plant investments and enhanced reliability and vegetation management programs. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy of $5.2 million effective July 1, 2010. Once permanent rates are approved by the NHPUC, they will be reconciled to the date temporary rates were ordered. The Company is currently engaged in settlement proceedings regarding the permanent rate level and a long-term rate plan. A hearing in this matter is scheduled for early February 2011.

On November 30, 2010 the Company's interstate natural gas transmission pipeline, Granite State, filed a rate settlement agreement, which provides for an increase of approximately $1.7 million in annual revenue effective January 1, 2011. This settlement agreement was approved by the FERC on January 31, 2011.

On January 14, 2011, the Company's Massachusetts operating utility, Fitchburg, filed a comprehensive revenue decoupling proposal and a request for distribution rate increases of $7.1 million for its electric division and $4.4 million of its gas division. The Company's filing also includes a rate-impact mitigation alternative for the electric division that would offset the distribution revenue increase through a corresponding decrease in Fitchburg's Transition Charge. The Transition Charge is the means by which Fitchburg recovers its power supply-related stranded costs and other restructuring-related regulatory assets. Any offsetting decrease in the Transition Charge would allow for the recovery of the restructuring related stranded costs over an extended term. The Company's revenue decoupling proposal is modeled closely on decoupling proposals already approved by the MDPU for other utilities operating in the Commonwealth of Massachusetts and is intended to align the Company's interests with important public policy objectives concerning energy efficiency, energy reliability, national energy security and protecting the environment. The MDPU issued an order suspending and deferring the use of the rates until August 2, 2011, pending an investigation and analysis of the Company's filing.

Northern Utilities, the Company's gas distribution utility operating in New Hampshire and Maine, is currently planning to file base rate cases for both its New Hampshire and Maine divisions in the second quarter of 2011. The Company will announce the amount of the requested rate increases and other related information after the filing of the distribution base rate cases.

Also see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Rates and Regulation.

NATURAL GAS SUPPLY

Unitil manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and C&I customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors. Many large and some medium C&I customers purchase their supplies from third-party suppliers, while most of Fitchburg's residential and small C&I customers continue to purchase their supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern Utilities purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern Utilities arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of LNG, to truck supplies to each storage facility within Northern Utilities' service territory.

Northern Utilities has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns an LNG storage and vaporization facility. This plant is used principally during peak load periods to augment the supply of pipeline natural gas.

ELECTRIC POWER SUPPLY

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third-party energy suppliers. As of December 2010, 104 or 70% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 87% of Unitil's largest Massachusetts customers, representing 36% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential, small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100% of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two two-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

In connection with the restructuring of the electric industry, Unitil Power, Unitil Energy and Fitchburg divested and sold substantially their power supply portfolios consisting of long-term power supply contracts and ownership interests in generation assets. Unitil Power, Unitil Energy and Fitchburg recover in their rates all the costs associated with this divestiture and sale and have secured regulatory approval from the FERC, NHPUC and MDPU, respectively, for the recovery of stranded costs, including long term contract buyout agreements, and other restructuring-related regulatory assets. The companies have a continuing obligation to submit regulatory filings that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

ENVIRONMENTAL MATTERS

Unitil's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed. Also, see Note 6 to the accompanying consolidated financial statements.

Fitchburg recovers the environmental response costs incurred at this former MGP site in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. In January 2011, Fitchburg settled with the remaining insurance carriers for approximately $2.0 million and expects to receive these payments in the first quarter of 2011. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are shared equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Also, see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES

As of December 31, 2010, the Company and its subsidiaries had 437 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2010, 150 of the Company's employees were represented by labor unions. These employees are covered by four separate collective bargaining agreements which expire on March 31, 2012, May 31, 2012, May 31, 2013 and June 5, 2014. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is www.unitil.com. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the New York Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of February 3, 2011:

Name	Age	Position
Robert G. Schoenberger	60	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	51	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	48	Senior Vice President and Chief Operating Officer
Laurence M. Brock	57	Controller and Chief Accounting Officer
Todd R. Black	46	Senior Vice President, External Affairs and Customer Relations, Unitil Service
George R. Gantz	59	Senior Vice President, Distributed Energy Resources, Unitil Service
George E. Long, Jr.	54	Vice President, Administration, Unitil Service
Sandra L. Whitney	47	Corporate Secretary
William D. Adams	63	Director
Dr. Robert V. Antonucci	65	Director
David P. Brownell	67	Director
Michael J. Dalton	70	Director
Albert H. Elfner, III	66	Director
Edward F. Godfrey	61	Director
Michael B. Green	61	Director
Eben S. Moulton	64	Director
M. Brian O'Shaughnessy	67	Director
Dr. Sarah P. Voll	68	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board of Directors and Chief Executive Officer since 1997, as well as President since 2003. Prior to his employment with Unitil, Mr. Schoenberger was president and chief operating officer of the New York Power Authority (a state-owned utility) from 1993 until 1997. Mr. Schoenberger has also served as a director of Satcon Technology Corporation, Boston, Massachusetts (a company that develops innovative power conversion solutions for the renewable power industry) since 2007. Mr. Schoenberger also serves as chairman of the Tocqueville Society of the Greater Seacoast (New Hampshire) United Way. Mr. Schoenberger formerly served as chairman and trustee of Exeter Health Resources, Exeter, New Hampshire, from 1998 until 2009, and as a director of the Southwest Power Pool from 2003 until 2005.

Mark H. Collin has been Unitil's Senior Vice President and Chief Financial Officer since February 2003. Mr. Collin has also served as Treasurer since 1998. Mr. Collin joined Unitil in 1988, and served as Vice President of Finance from 1995 until 2003.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President and Chief Operating Officer since June 2005. Mr. Meissner served as Senior Vice President, Operations, from February 2003 until June 2005. Mr. Meissner joined Unitil in 1994 and served as Director of Engineering from 1998 until 2003.

George R. Gantz has been Unitil's Senior Vice President, Distributed Energy Resources, Unitil Service, since September 2009. Mr. Gantz joined Unitil in 1983 and served as Senior Vice President, Communication and Regulation from 1994 until 2003, and Senior Vice President, Customer Services and Communications from 2003 until 2009.

Todd R. Black has been Unitil's Senior Vice President, External Affairs and Customer Relations, Unitil Service, since September 2009. Mr. Black joined Unitil in 1998 and served as Vice President, Sales and Marketing, for Usource from 1998 until 2003, and President of Usource from 2003 until 2009.

Laurence M. Brock has been Unitil's Controller and Chief Accounting Officer since June 2005. Mr. Brock joined Unitil in 1995 as Vice President and Controller, and is a certified public accountant in the state of New Hampshire.

George E. Long, Jr. has been Unitil's Vice President, Administration, Unitil Service, since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources, from 1998 until 2003.

Sandra L. Whitney has been Unitil's Corporate Secretary and secretary of our Board of Directors since February 2003. Ms. Whitney joined Unitil in 1990 and also serves as the Corporate Secretary of Unitil's subsidiary companies.

William D. Adams has been a member of Unitil's Board of Directors since 2009. Mr. Adams has been the president of Colby College in Waterville, Maine, since 2000. Mr. Adams also serves on the board of trustees of Colby College. Prior to going to Colby, Mr. Adams served as president of Bucknell University in Pennsylvania from 1995 until 2000. Prior to leading Bucknell, he served as vice president and secretary of Wesleyan University in Connecticut. Mr. Adams also served as coordinator of the Great Works in Western Culture program at Stanford University and taught political philosophy at the University of North Carolina at Chapel Hill and Santa Clara University. Mr. Adams has served on the board of directors of Wittenberg University since 2007, and Maine Public Broadcasting Corporation since 2002. Mr. Adams was also a director of Maine General Health from 2002 to 2010.

Dr. Robert V. Antonucci has been a member of Unitil's Board of Directors since 2004. Dr. Antonucci has been the president of Fitchburg State University (FSU) in Fitchburg, Massachusetts, since 2003. Prior to his employment with FSU, Dr. Antonucci was president of the School Group of Riverdeep, Inc., San Francisco, California, from 2001 until 2003 and president and chief executive officer of Harcourt Learning Direct and Harcourt Online College, Chestnut Hill, Massachusetts from 1998 until 2001. Dr. Antonucci also served as the commissioner of education for the Commonwealth of Massachusetts from 1992 until 1998. In addition, Dr. Antonucci has served as a trustee of Eastern Bank since 1988. Dr. Antonucci also serves as a director of the North Central Massachusetts Chamber of Commerce and a director of the North Central Massachusetts United Way.

David P. Brownell has been a member of Unitil's Board of Directors since 2001. Mr. Brownell has been a retired senior vice president of Tyco International Ltd. (Tyco) (a diversified global manufacturing and service company), Portsmouth, New Hampshire, since 2003. Mr. Brownell had been with Tyco since 1984. Mr. Brownell was also interim president of the University of New Hampshire (UNH) Foundation, former vice chairman of the board of UNH Foundation, former volunteer board president of the United Way of the Greater Seacoast, and a former board member of the New Hampshire Junior Achievement Advisory Council.

Michael J. Dalton has been a member of Unitil's Board of Directors since 1984. Mr. Dalton retired as President and Chief Operating Officer of Unitil in 2003. Mr. Dalton is a member of the Industrial Advisory Council of the UNH College of Engineering and Physical Science and Vice President of the Alumni Society of the College of Engineering and Physical Science. In addition, Mr. Dalton also serves as a mentor with the UNH Pathways Mentorship Program. Mr. Dalton was formerly a director of the New England Gas Association, the Electric Council of New England, the UNH Foundation, the UNH Alumni Association, and the UNH President's Council.

Albert H. Elfner, III has been a member of Unitil's Board of Directors since 1999. Mr. Elfner was the chairman of Evergreen Investment Management Company, Boston, Massachusetts, from 1994 until 1999 and its chief executive officer from 1995 until 1999. Mr. Elfner is also a director of Main Street America Insurance Company (Main Street), Jacksonville, Florida, as well as chairman of the Main Street finance committee.

Edward F. Godfrey has been a member of Unitil's Board of Directors since 2002. Mr. Godfrey was the executive vice president and chief operating officer of Keystone Investments, Incorporated (Keystone), Boston, Massachusetts, from 1997 until 1998. Mr. Godfrey was senior vice president, chief financial officer and treasurer of Keystone from 1988 until 1996. Mr. Godfrey is also a director of Vector Fleet Management, LLC, Charlotte, North Carolina, since 2006.

Michael B. Green has been a member of Unitil's Board of Directors since 2001. Mr. Green has been the president and chief executive officer of Capital Region Health Care and Concord Hospital, Concord, New Hampshire, since 1992. Mr. Green is also a member of the adjunct faculty, Dartmouth Medical School, Dartmouth College, Hanover, New Hampshire. In addition, Mr. Green currently serves on the board of the Foundation for Healthy Communities, is a director of the New Hampshire Hospital Association, a director of Concord General Mutual Insurance Company, and a director of Merrimack County Savings Bank (Merrimack), including membership on Merrimack's investment and audit committees.

Eben S. Moulton has been a member of Unitil's Board of Directors since 2000. Mr. Moulton has been the managing partner of Seacoast Capital Corporation, Danvers, Massachusetts, (a private investment company) since 1995. Mr. Moulton is also a director of IEC Electronics Corp. (a company that provides electronic manufacturing services to advanced technology companies), Newark, New York, and a director of six private companies.

M. Brian O'Shaughnessy has been a member of Unitil's Board of Directors since 1998. Mr. O'Shaughnessy has been the chairman of the board of Revere Copper Products, Inc. (Revere), Rome, New York, since 1988. Mr. O'Shaughnessy also served as chief executive officer and president of Revere from 1988 until 2007. Mr. O'Shaughnessy also serves on the Board of Directors and as the chief co-chair of the Coalition for a Prosperous America, three copper industry trade associations, three manufacturing associations in New York State regarding energy-related issues, and the Economic Development Growth Enterprise of Mohawk Valley.

Dr. Sarah P. Voll has been a member of Unitil's Board of Directors since 2003. Dr. Voll retired in 2007 as vice president from National Economic Research Associates, Inc. (NERA), Washington, District of Columbia, a firm of consulting economists specializing in industrial and financial economics, and currently serves as a special consultant to NERA. Dr. Voll had been with NERA in the position of vice president since 1999, and in the position of senior consultant from 1996 until 1999. Prior to her employment with NERA, Dr. Voll was a staff member at the NHPUC from 1980 until 1996.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 21, 2011, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, Computershare, is responsible for shareholder records, issuance of common stock, administration of the Dividend Reinvestment and Stock Purchase Plan, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact Computershare at:

Computershare
P.O. Box 43078
Providence, RI 02940-3078
Telephone: 800-736-3001
www.computershare.com

Investor Relations

For information about the Company, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investors page at *www.unitil.com*; or contact the transfer agent, Computershare, at the number listed above.

Special Services & Shareholder Programs Available to Holders of Record

If a shareholder's shares of common stock are registered directly in the shareholder's name with the Company's transfer agent, the shareholder is considered a holder of record of the shares. The following services and programs are available to shareholders of record:

- Internet Account Access is available at *www.computershare.com*.
- Dividend Reinvestment and Stock Purchase Plan:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative or Computershare.
- Direct Registration:

  For information, please contact Computershare at 800-935-9330 or the Company's Investor Relations Representative at 800-999-6501.

Item 1A. Risk Factors

Risks Relating to Our Business

The Company is subject to comprehensive regulation, which could impact the rates it is able to charge, its authorized rate of return and its ability to recover costs. This could adversely affect the Company's financial condition or results of operations. In addition, certain regulatory authorities have the power to impose finance penalties and other sanctions on the Company, which could adversely affect the Company's financial condition or results of operations.

The Company is subject to comprehensive regulation by federal regulatory authorities (including the FERC) and state regulatory authorities (including the NHPUC, MDPU and MPUC). These authorities regulate many aspects of the Company's operations, including the rates that the Company can charge customers, the Company's authorized rates of return, the Company's ability to recover costs from its customers, construction and maintenance of the Company's facilities, the Company's safety protocols and procedures, the Company's ability to issue securities, the Company's accounting matters, and transactions between the Company and its affiliates. The Company is unable to predict the impact on its financial condition or results of operations from the regulatory activities of any of these regulatory authorities. Also, changes in regulations or the imposition of additional regulations could adversely affect the Company's financial condition or results of operations.

The Company's ability to obtain rate adjustments to maintain its current authorized rates of return depends upon action by regulatory authorities under applicable statutes, rules and regulations. These regulatory authorities are authorized to leave the Company's rates unchanged, to grant increases in such rates or to order decreases in such rates. The Company may be unable to obtain favorable rate adjustments or to maintain its current authorized rates of return, which could adversely affect its financial condition or results of operations.

Regulatory authorities also have authority with respect to the Company's ability to recover its electricity and natural gas supply costs, as incurred by Unitil Power, Unitil Energy, Fitchburg, and Northern Utilities. If the Company is unable to recover a significant amount of these costs, or if the Company's recovery of these costs is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

In addition, certain regulatory authorities have the power to impose financial penalties and other sanctions on the Company if the Company is found to have violated statutes, rules or regulations governing its utility operations. This could adversely affect the Company's financial condition or results of operations. Please see (i) the section entitled *Regulatory Matters—Fitchburg—Gas Operations* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) the section entitled *Regulatory Matters—Fitchburg—Gas* Operations in Note 6 (Commitments and Contingencies) to the accompanying Consolidated Financial Statements.

Severe storms have struck, and may strike, the New England region, causing extensive damage to the Company's utility operations and the loss of service to significant numbers of the Company's customers. If the Company is unable to recover a significant amount of storm costs in its rates, or if the Company's recovery of storm costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

Please see (i) the sections entitled *Regulatory Matters—Major Wind Storm* and *Regulatory Matters—Major Ice Storm* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) the sections entitled *Regulatory Matters—Major Wind Storm* and *Regulatory Matters—Major Ice Storm* in Note 6 (Commitments and Contingencies) to the accompanying Consolidated Financial Statements.

As a result of electric industry restructuring, the Company has a significant amount of stranded electric generation and power supply related supply costs. If the Company is unable to recover a significant amount of stranded costs in its rates, or if the Company's recovery of stranded costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

The stranded electric generation and power supply related supply costs resulting from the implementation of electric industry restructuring mandated by the states of New Hampshire and Massachusetts are recovered by the Company on a pass-through basis through periodically reconciled rates. Any unrecovered balance of stranded costs is deferred for future recovery as a regulatory asset. Such regulatory assets are subject to periodic regulatory review and approval for recovery in future periods.

Substantially all of the Company's stranded costs relate to (i) Unitil Power's long-term power purchase agreements (which Unitil Power divested under long-term contract buyout agreements) and (ii) Fitchburg's formerly owned generation assets and purchase power agreements (which Fitchburg divested under a long-term contract buy-out agreement). Unitil Power made the final payment on its long-term contract buyout agreements in October 2010, which ended its obligations in the underlying purchase power contracts. As a result, in accordance with its retail stranded cost recovery rates, substantially all of Unitil Energy's stranded costs are projected to be fully recovered by July 31, 2011. Because Fitchburg continues to remain ultimately responsible for purchase power payments underlying its long-term buyout agreements, Fitchburg could incur additional stranded costs were they required to resell such divested entitlements prior to the end of their term for amounts less than the amounts agreed to under the existing long-term buyout agreements. The Company expects that any such additional stranded costs would be recovered from its customers, however such recovery would require approval from the MDPU, the receipt of which cannot be assured. If the Company is unable to recover a significant amount of such stranded costs in its rates, or if the Company's recovery of such stranded costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected. Please see (i) the section entitled *Regulatory Matters—Overview (Unitil Energy, Fitchburg, and Northern Utilities)* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) the section entitled *Regulatory Matters—Overview (Unitil Energy, Fitchburg, and Northern Utilities)* in Note 6 (Commitments and Contingencies) to the accompanying Consolidated Financial Statements.

The Company's electric and natural gas sales and revenues are highly correlated with the economy, and national, regional and local economic conditions may adversely affect the Company's customers and correspondingly the Company's financial condition or results of operations.

The Company's business is influenced by the economic activity within its service territory. The level of economic activity in the Company's electric and natural gas distribution service territory directly affects the Company's business. As a result, adverse changes in the economy may adversely affect the Company's financial condition or results or operations.

The Company may not be able to obtain financing, or may not be able to obtain financing on acceptable terms, which could adversely affect the Company's financial condition or results of operations.

The Company requires capital to fund utility plant additions, working capital and other utility expenditures. While the Company derives the capital necessary to meet these requirements primarily from internally-generated funds, the Company supplements internally generated funds by incurring short-term debt under its current credit facility, as needed. If the lending counterparties under the Company's current credit facility are unwilling or unable to meet their funding obligations, then the Company may be unable to, or limited in its ability to, incur short-term debt under its credit facility. This could hinder or prevent the Company from meeting its current and future capital needs, which could correspondingly adversely affect the Company's financial condition or results or operations.

Also, from time to time, the Company repays portions of its short-term debt with the proceeds it receives from long-term debt financings or equity financings. General economic conditions and the Company's operating and financial performance could negatively affect the Company's ability to obtain such financings and the terms of such financings, which could correspondingly adversely affect the Company's financial condition or results or operations.

Declines in the valuation of capital markets could require the Company to make substantial cash contributions to cover its pension obligations. If the Company is unable to recover a significant amount of pension obligation costs in its rates, or if the Company's recovery of pension obligation costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

Please see (i) the section entitled *Critical Accounting Policies—Pension Benefit Obligations* in Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) and (ii) Note 10 (Retirement Benefit Plans) to the accompanying Consolidated Financial Statements.

Increases in interest rates could increase the Company's interest expense and adversely affect the Company's financial condition or results of operations.

The Company and its utility subsidiaries have ongoing capital expenditure and cash funding requirements, which they frequently fund by issuing short-term debt and long-term debt.

The Company's short-term debt revolving credit facility typically has variable interest rates. Therefore, an increase or decrease in interest rates will increase or decrease the Company's interest expense associated with its revolving credit facility. An increase in the Company's interest expense could adversely affect the Company's financial condition or results of operations. As of December 31, 2010, the Company had approximately $66.8 million in short-term debt outstanding under its revolving credit facility.

The Company's long-term debt typically has fixed interest rates. Therefore, changes in interest rates will not affect the Company's interest expense associated with its presently outstanding fixed rate long-term debt. However, an increase or decrease in interest rates may increase or decrease the Company's interest expense associated with any new fixed rate long-term debt issued by the Company, which could adversely affect the Company's financial condition or results of operations. See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

In addition, the Company may need to use a significant portion of its cash flow to repay its short-term debt and long-term debt, which would limit the amount of cash it has available for working capital, capital expenditures and other general corporate purposes and could adversely affect its financial condition or results of operations.

The terms of the Company's and its subsidiaries' indebtedness restrict the Company's business operations (including their ability to incur material amounts of additional indebtedness), which could adversely affect the Company's financial condition or results or operations.

See Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, Commitments and Capital Requirements section and Note 4 to the accompanying Consolidated Financial Statements.

A significant amount of the Company's sales are temperature sensitive. Because of this, mild winter and summer temperatures could decrease the Company's sales, which could adversely affect the Company's financial condition or results or operations. Also, the Company's sales may vary from year to year depending on weather conditions, and the Company's results of operations generally reflect seasonality.

The Company estimates that approximately 50% of its annual natural gas sales are temperature sensitive. Therefore, mild winter temperatures could decrease the amount of natural gas sold by the Company, which could adversely affect the Company's financial condition or results of operations. The Company's electric sales also are temperature sensitive, but less so than its natural gas sales. The highest usage of electricity typically occurs in the summer months (due to air conditioning demand) and the winter months (due to heating-related and lighting requirements). Therefore, mild summer temperatures and mild winter temperatures could decrease the amount of electricity sold by the Company, which could adversely affect the Company's financial condition and results of operations. Also, because of this temperature sensitivity, sales by the Company's distribution utilities vary from year to year, depending on weather conditions.

In addition, the Company's results of operations generally reflect seasonality. In particular, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher (due to heating-related requirements), and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Long-term global climate change could adversely affect customer demand or cause extreme weather events that could disrupt the Company's electric and natural gas distribution services.

Milder winter and summer temperatures due to long-term global climate change may cause a decrease in the amount of natural gas and electricity sold by the Company, which could correspondingly adversely affect the Company's financial condition and results or operations. Conversely, colder winter temperatures and warmer summer temperatures due to long-term global climate change may cause an increase in the amount of natural gas and electricity sold by the Company.

In addition, extreme weather events (such as hurricanes and severe winter storms) related to long-term global climate change may damage facilities or result in increased service interruptions and outages and increase the Company's operations and maintenance costs. If the Company is unable to recover a significant amount of such costs in its rates, or if the Company's recovery of such costs in its rates is significantly delayed, then the Company's financial condition or results or operations could be adversely affected.

The Company is unable to predict the impacts on its financial condition and results or operations due to changes in weather related to long-term global climate change.

Unitil is a public utility holding company and has no operating income of its own. The Company's ability to pay dividends on its common stock is dependent on dividends and other payments received from its subsidiaries and on factors directly affecting Unitil, the parent corporation. The Company cannot assure you that its current annual dividend will be paid in the future.

The ability of the Company's subsidiaries to pay dividends or make distributions to Unitil depends on, among other things:

- the actual and projected earnings and cash flow, capital requirements and general financial condition of the Company's subsidiaries;
- the prior rights of holders of existing and future preferred stock, mortgage bonds, long-term notes and other debt issued by the Company's subsidiaries;
- the restrictions on the payment of dividends contained in the existing loan agreements of the Company's subsidiaries and that may be contained in future debt agreements of the Company's subsidiaries, if any; and
- limitations that may be imposed by New Hampshire, Massachusetts and Maine state regulatory agencies.

In addition, before the Company can pay dividends on its common stock, it has to satisfy its debt obligations and comply with any statutory or contractual limitations.

The Company's current annual dividend is $1.38 per share of common stock, payable quarterly. However, the Company's Board of Directors reviews Unitil's dividend policy periodically in light of the factors referred to above, and the Company cannot assure the amount of dividends, if any, that may be paid in the future.

The Company's electric and natural gas distribution activities (including storing natural gas and supplemental gas supplies) involve numerous hazards and operating risks that may result in accidents and other operating risks and costs. Any such accident or costs could adversely affect the Company's financial position and results of operations.

Inherent in the Company's electric and natural gas distribution activities are a variety of hazards and operating risks, including leaks, explosions, electrocutions and mechanical problems. These hazards and risks could result in loss of human life, significant damage to property, environmental pollution, damage to natural resources and impairment of the Company's operations, which could adversely affect the Company's financial position and results of operations.

The Company maintains insurance against some, but not all, of these risks and losses in accordance with customary industry practice. The location of pipelines, storage facilities and electric distribution equipment near populated areas (including residential areas, commercial business centers and industrial sites) could increase the level of damages associated with these risks. The occurrence of any of these events could adversely affect the Company's financial position or results of operations.

The Company's business is subject to environmental regulation in all jurisdictions in which it operates and its costs of compliance are significant. New or changes to existing environmental regulation, including related to climate change or greenhouse gas emissions, and the incurrence of environmental liabilities could adversely affect the Company's financial condition or results of operations.

The Company's utility operations are generally subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources, and the health and safety of the Company's employees. The Company's utility operations also may be subject to new and emerging federal, state and local legislative and regulatory initiatives related to climate change or greenhouse gas emissions including the U.S. Environmental Protection Agency's mandatory greenhouse gas reporting rule. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties and other sanctions; imposition of remedial requirements; and issuance of injunctions to ensure future compliance. Liability under certain environmental laws and regulations is strict, joint and several in nature. Although the Company believes it is in material compliance with all applicable environmental and safety laws and regulations, there can be no assurance that the Company will not incur significant costs and liabilities in the future. Moreover, it is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations, including those related to climate change or greenhouse gas emissions, could result in increased environmental compliance costs.

Catastrophic events could adversely affect the Company's financial condition or results of operations.

The electric and natural gas utility industries are from time to time affected by catastrophic events, such as unusually severe weather and significant and widespread failures of plant and equipment. Other catastrophic occurrences, such as terrorist attacks on utility facilities, may occur in the future. Such events could inhibit the Company's ability to provide electric or natural gas distribution services to its customers for an extended period, which could adversely affect the Company's financial condition and results of operations.

The Company's business could be adversely affected if it is unable to retain its existing customers or attract new customers.

The success of the Company's business depends, in part, on its ability to maintain and increase its customer base. The Company's failure to maintain or increase its customer base could adversely affect its financial condition and results of operations.

The Company's energy brokering customers may default in their performance under multi-year energy brokering contracts, which could adversely affect the Company's financial condition and results of operations.

The Company's non-regulated energy brokering business provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenues from this business are primarily derived from brokering fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts. The Company's customers may default in their performance under multi-year energy brokering contracts, which could adversely affect the Company's financial condition and results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2010, Unitil owned, through its distribution utilities, three utility operation centers, approximately 2,181 pole miles of local transmission and distribution overhead electric lines and 549 cable miles of underground electric distribution lines, along with 49 electric substations, including four mobile electric substations. Our natural gas operations property includes two liquid propane gas plants, two liquid natural gas plants and 1,280 miles of underground gas mains. In addition, our real estate subsidiary, Unitil Realty, owns our corporate headquarters building and the 12 acres of land on which it is located.

Unitil Energy owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. Unitil Energy's 30 electric distribution substations, including a 5,000 kilovolt ampere (kVA) and a 10,500 kVA mobile substation, constitute 219,002 kVA of capacity, which excludes capacity of spare transformers, for the transformation of electric power from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by Unitil Energy or land occupied by Unitil Energy pursuant to perpetual easements.

Unitil Energy has a total of approximately 1,619 pole miles of local transmission and distribution overhead electric lines and a total of 368 cable miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Unitil Energy without objection by the owners. In the case of certain distribution lines, Unitil Energy owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

The physical utility properties of Unitil Energy, with certain exceptions, and its franchises are subject to its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of Unitil Energy are outstanding.

Fitchburg's electric properties consist principally of 562 pole miles of local transmission and distribution overhead electric lines, 181 cable miles of underground electric distribution lines and 19 transmission and distribution stations (including two mobile electric substations). The capacity of these substations totals 441,650 kVA, which excludes capacity of spare transformers.

Fitchburg owns a liquid propane gas plant and a liquid natural gas plant, both of which are located on land owned by Fitchburg. Fitchburg also has 263 miles of underground steel, cast iron and plastic gas mains.

Fitchburg's electric substations, with minor exceptions, are located on land owned by Fitchburg or occupied by Fitchburg pursuant to perpetual easements. Fitchburg's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by Fitchburg without objection by the owners. Fitchburg leases its distribution operations center located in Fitchburg, Massachusetts.

Northern Utilities' distribution system is comprised of 1,017 miles of gas mains and 38,450 service pipes. The gas mains are primarily made up of polyethylene plastic (69%), coated and wrapped cathodically protected steel (19%), cast/wrought iron (7%), and unprotected bare and coated steel (5%).

Northern Utilities' New Hampshire division serving 21 communities has 499 miles of distribution gas mains and 20,844 service pipes. Northern Utilities' Maine division serving 23 communities has 518 miles of distribution and 17,606 service pipes. Northern Utilities also owns a liquid propane gas plant and a LNG storage and vaporization facility.

Granite State is a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline located primarily in Maine and New Hampshire.

The Company believes that its facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2011. The Company continues to believe the suit is without merit and will defend itself vigorously.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's common stock is listed on the New York Stock Exchange under the symbol "UTL". As of December 31, 2010, there were 1,597 shareholders of record.

Common Stock Data

Dividends per Common Share	2010	2009
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2010		2009	
Price Range of Common Stock	High/Ask	Low/Bid	High/Ask	Low/Bid
1st Quarter	**$24.40**	**$20.46**	$20.75	$17.50
2nd Quarter	**$24.36**	**$19.28**	$22.83	$18.76
3rd Quarter	**$22.99**	**$20.55**	$23.26	$20.19
4th Quarter	**$23.49**	**$21.22**	$23.67	$19.31

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

Equity Compensation Plan Benefit Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
Restricted Stock Plan (1)	—	N/A	62,790
Equity compensation plans not approved by security holders			
1998 Option Plan (2)	33,000	$25.88	—
Total	33,000	$25.88	62,790

NOTES: (also see Note 3 to the accompanying Consolidated Financial Statements)

(1) The Restricted Stock Plan (the Plan) was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004; 10,900 shares of restricted stock were awarded to Plan participants in March 2005; 14,375 shares of restricted stock were awarded to Plan participants in February 2006; 9,020 shares of restricted stock were awarded to Plan participants in February 2007; 15,540 shares of restricted stock were awarded to Plan participants in February 2008; 32,260 shares of restricted stock were awarded to Plan participants in February 2009. 12,520 shares of restricted stock were awarded to Plan participants in February 2010.

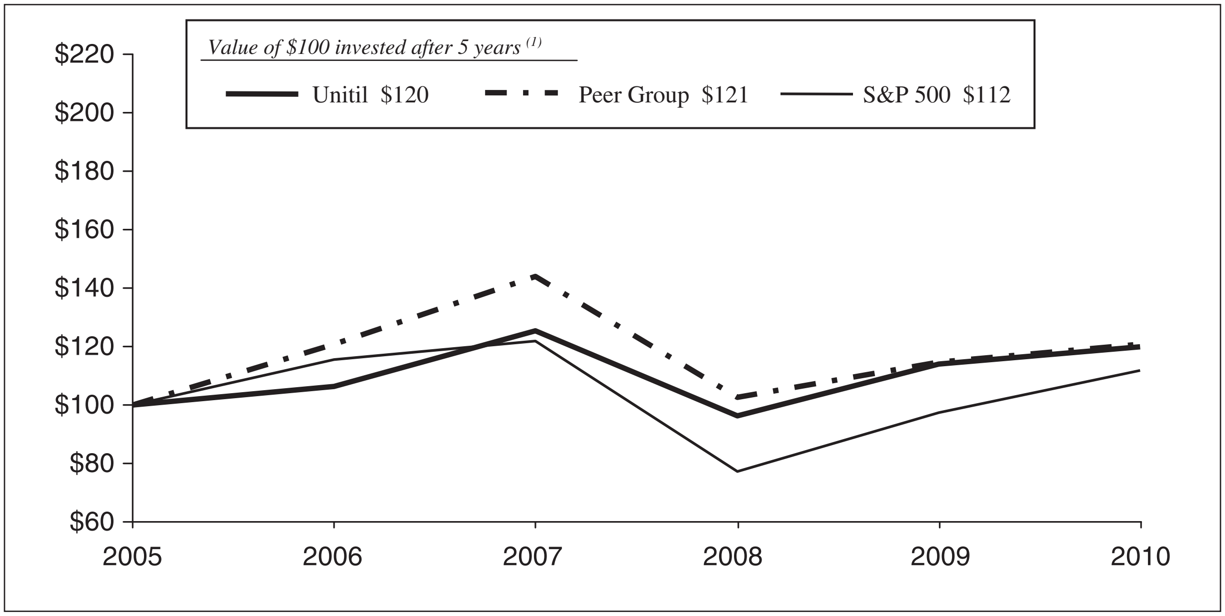
(2) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange (the exchange upon which the Company was then listed) rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the 1998 Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the 1998 Option Plan were

deregistered with the Securities and Exchange Commission. Since the plan's termination by Board of Directors, no further grants of options were made thereunder. The remaining 33,000 options expired on January 16, 2011 without being exercised.

Stock Performance Graph

The following graph compares Unitil Corporation's cumulative stockholder return since December 31, 2005 with the Peer Group index, comprised of the S&P Utility Index, and the S&P 500 index. The graph assumes that the value of the investment in the Company's common stock and each index (including reinvestment of dividends) was $100 on December 31, 2005.

Comparative Five-Year Total Returns



NOTE:

(1) The graph above assumes $100 invested on December 31, 2005, in each category and the reinvestment of all dividends during the five-year period. The Peer Group is comprised of the S&P Utility Index.

Unregistered Sales of Equity Securities and Uses of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2010.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 25, 2010, the Company will periodically repurchase shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. There is no pool or maximum number of shares related to these purchases; however, the trading plan will automatically terminate when $80,700 in value of shares have been purchased, or, if sooner, on March 25, 2011.

The Company may suspend or terminate this trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
10/1/10 – 10/31/10	—	—	—
11/1/10 – 11/30/10	—	—	—
12/1/10 – 12/31/10	2,497	$22.98	2,497
Total	2,497	$22.98	2,497

Item 6. Selected Financial Data

For the Years Ended December 31,	2010	2009	2008	2007	2006
(all data in millions except shares, % and per share data) [1]					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 358.4**	$ 367.0	$ 288.2	$ 262.9	$ 260.9
Operating Income	**28.0**	26.1	20.5	18.5	15.8
Other Non-operating Expense	**0.3**	0.3	0.3	0.2	—
Income Before Interest Expense	**27.7**	25.8	20.2	18.3	15.8
Interest Expense, net	**18.1**	15.8	10.5	9.6	7.8
Net Income	**9.6**	10.0	9.7	8.7	8.0
Dividends on Preferred Stock	**0.1**	0.1	0.1	0.1	0.1
Earnings Applicable to Common Shareholders	**$ 9.5**	$ 9.9	$ 9.6	$ 8.6	$ 7.9
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 728.4**	$ 682.7	$ 641.4	$ 380.5	$ 353.0
Total Assets	**$ 759.6**	$ 725.2	$ 733.2	$ 474.6	$ 483.4
Capitalization:					
Common Stock Equity	**$ 189.0**	$ 193.1	$ 139.5	$ 100.4	$ 97.8
Preferred Stock	**2.0**	2.0	2.0	2.1	2.1
Long-Term Debt, less current portion	**288.3**	248.9	249.3	159.6	140.0
Total Capitalization	**$ 479.3**	$ 444.0	$ 390.8	$ 262.1	$ 239.9
Current Portion of Long-Term Debt	**$ 0.5**	$ 0.4	$ 0.4	$ 0.4	$ 0.3
Short-term Debt	**$ 66.8**	$ 64.5	$ 74.1	$ 18.8	$ 26.0
Capital Structure Ratios:					
Common Stock Equity	**39%**	43%	36%	38%	41%
Preferred Stock	**1%**	1%	1%	1%	1%
Long-Term Debt	**60%**	56%	63%	61%	58%
Earnings Per Share Data:					
Earnings Per Average Share	**$ 0.88**	$ 1.03	$ 1.65	$ 1.52	$ 1.41
Common Stock Data:					
Shares of Common Stock—(Diluted Average Outstanding, 000's)	**10,824**	9,647	5,830	5,672	5,612
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.35**	$ 17.83	$ 17.90	$ 17.50	$ 17.30
Electric and Gas Sales:					
Electric Distribution Sales (Millions kWh)	**1,691.1**	1,618.8	1,695.9	1,743.0	1,751.5
Firm Natural Gas Distribution Sales (Millions Therms)	**172.9**	178.7	47.2	28.4	26.4

(1) As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in all reporting periods.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

OVERVIEW

Unitil is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company from NiSource.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy, which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,900 electric customers and 70,800 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite State, a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to North American pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and Unitil had an investment in Net Utility Plant of $476.5 million at December 31, 2010. Unitil's total revenue was $358.4 million in 2010, which includes revenue to recover the approved cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not affected by changes in the cost of purchased electricity and natural gas. Earnings from Unitil's utility operations are derived from the return on investment in the three distribution utilities and Granite State.

Unitil also conducts non-regulated operations principally through Usource, which is wholly-owned by Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Usource's total revenues were $4.6 million in 2010. The Company's other subsidiaries include Unitil Service, which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, and Unitil Realty, which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- the Company's regulatory environment (including regulations relating to climate change, greenhouse gas emissions and other environmental matters), which could impact the rates the Company is able to charge, the Company's authorized rate of return and the Company's ability to recover costs in its rates;
- fluctuations in the supply of, demand for, transmission capacity and the prices of energy commodities and the Company's ability to recover energy commodity costs in its rates;
- customers' preferences on energy sources;
- severe storms and the Company's ability to recover storm costs in its rates;
- the Company's stranded electric generation and generation-related supply costs and the Company's ability to recover stranded costs in its rates;
- declines in the valuation of capital markets, which could require the Company to make substantial cash contributions to cover its pension obligations, and the Company's ability to recover pension obligation costs in its rates;
- general economic conditions, which could adversely affect (i) the Company's customers and, consequently, the demand for the Company's distribution services, (ii) the availability of credit and liquidity resources and (iii) certain of the Company's counterparty's obligations (including those of its insurers and lenders);
- the Company's ability to obtain debt or equity financing on acceptable terms;
- increases in interest rates, which could increase the Company's interest expense;
- restrictive covenants contained in the terms of the Company's and its subsidiaries' indebtedness, which restrict certain aspects of the Company's business operations;
- variations in weather, which could decrease demand for the Company's distribution services;
- long-term global climate change, which could adversely affect customer demand or cause extreme weather events that could disrupt the Company's electric and natural gas distribution services;
- numerous hazards and operating risks relating to the Company's electric and natural gas distribution activities, which could result in accidents and other operating risks and costs;
- catastrophic events;
- the Company's ability to retain its existing customers and attract new customers;
- the Company's energy brokering customers' performance under multi-year energy brokering contracts; and
- increased competition.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

See also Item 1A Risk Factors.

RESULTS OF OPERATIONS

The following discussion of the Company's financial condition and results of operations should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 8 of this report.

Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the financing associated with the Acquisitions. As a result of the Acquisitions and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisitions and stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher (due to heating-related requirements), and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Net Income and EPS Overview

2010 Compared to 2009—The Company's Earnings Applicable to Common Shareholders (Earnings) were $9.5 million, or $0.88 per share, for the full year of 2010. This compares to Earnings of $9.9 million, or $1.03 per share in 2009.

The Company's Earnings were $5.2 million, or $0.48 per share, for the fourth quarter of 2010, compared to Earnings of $1.2 million, or $0.11 per share in the fourth quarter of 2009. The results for 2009 include a non-recurring accounting charge in the fourth quarter for a regulatory order in Massachusetts requiring the refund $4.9 million of natural gas supply costs. The Company has appealed this order to the Massachusetts Supreme Judicial Court and anticipates a ruling in late 2011.

Electric sales margin increased $4.8 million in 2010 compared to 2009. The increase in electric sales margin reflects higher electric kilowatt-hour (kWh) sales and an electric rate increase implemented in July 2010 for Unitil Energy, the Company's New Hampshire electric operating utility. The increase in electric sales reflects higher than average summer temperatures in the Company's utility service territories in 2010 coupled with an improving regional economy. According to ISO-New England, the electric transmission grid operator for the New England region, July of 2010 was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month. On a weather-normalized basis, kWh sales in 2010 increased approximately 1.6% compared to 2009.

Natural gas sales margin increased $2.3 million in 2010 compared to 2009, reflecting the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above. Absent the effect of this refund, natural gas sales margin decreased $2.6 million in 2010 compared to 2009, principally due to the milder winter heating season in the early part of 2010 compared to 2009. Heating Degree Days in 2010 were 9% fewer than in the prior year. On a weather-normalized basis, natural gas therm sales for the full year of 2010 were essentially flat with therm sales in 2009.

Total Operation & Maintenance (O&M) expenses increased $4.1 million in 2010 compared to 2009. The changes in O&M expenses reflect higher utility operating costs. O&M expenses in 2010 also reflect the full integration of Northern Utilities and Granite State into the Company's consolidated operating results. In 2009, the Company recognized professional fees of approximately $3.0 million related to regulatory and legal matters concerning the Company's preparation and response to the severe ice storm that struck the New England region in December 2008.

Depreciation and Amortization expense increased $1.5 million in 2010 compared to 2009, reflecting higher depreciation on normal utility plant additions partially offset by lower amortization expense in the current year.

Interest Expense, net increased $2.3 million in 2010 compared to 2009. The increase is primarily due to the issuance of $40 million of long-term notes by Unitil Energy and Northern Utilities in March 2010.

Federal and State Income Taxes decreased by $0.9 million in 2010 due to lower pre-tax income in 2010 compared to 2009.

All other expenses increased $0.8 million in 2010 compared to 2009, primarily reflecting higher property taxes and payroll taxes.

Usource, our non-regulated energy brokering business, recorded revenues of $4.6 million in 2010, an increase of $0.3 million compared to 2009.

In 2010, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2011 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share.

2009 Compared to 2008—The Company's Earnings Applicable to Common Shareholders was $9.9 million for 2009, compared to $9.6 million for 2008. Earnings per common share were $1.03 for 2009, ($0.62) per share lower than earnings of $1.65 in 2008. The lower earnings per common share primarily reflect higher regulatory and legal expenses in 2009 associated with the severe ice storm that struck New England in December 2008 and other significant non-recurring regulatory matters.

A more detailed discussion of the Company's 2010 and 2009 results of operations and a year-to-year comparison of changes in financial position are presented below.

Gas Sales, Revenues and Margin

Therm Sales—Unitil's total therm sales of natural gas decreased 3.2% in 2010 compared to 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of milder winter temperatures in the early part of 2010 compared to 2009. Heating Degree Days in 2010 were 9% fewer than in the prior year. On a weather-normalized basis, natural gas therm sales in 2010 were essentially flat compared to 2009.

Unitil's total therm sales of natural gas increased 278.6% in 2009 compared to 2008, reflecting the contribution to sales by Northern Utilities. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas decreased 0.7% in 2009 compared to 2008, reflecting a decrease of 2.0% in sales to residential customers and flat year over year sales to C&I customers. The decrease in sales to residential customers reflects lower average usage by our customers, due to a slowing economy and energy conservation, partially offset by a colder winter heating season in the first quarter of 2009.

The following table details total therm sales for the last three years, by major customer class:

Therm Sales (millions)				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	Therms	%	Therms	%
Residential	**35.1**	36.7	13.3	(1.6)	(4.4%)	23.4	175.9%
Commercial / Industrial	**137.8**	142.0	33.9	(4.2)	(3.0%)	108.1	318.9%
Total	**172.9**	178.7	47.2	(5.8)	(3.2%)	131.5	278.6%

Gas Operating Revenues and Sales Margin—The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenues and Sales Margin (millions)

				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$	%(1)	$	%(1)
Gas Operating Revenue:							
Residential	**$ 61.5**	$ 62.0	$27.5	$(0.5)	(0.3%)	$34.5	60.6%
Commercial / Industrial	**88.6**	90.8	29.4	(2.2)	(1.4%)	61.4	107.9%
Total Gas Operating Revenue	**$150.1**	$152.8	$56.9	$(2.7)	(1.7%)	$95.9	168.5%
Cost of Gas Sales:							
Purchased Gas	**$ 90.5**	$ 96.4	$37.3	$(5.9)	(3.8%)	$59.1	103.9%
Conservation & Load Management	**2.8**	1.9	0.2	0.9	0.6%	1.7	2.9%
Total Cost of Gas Sales	**$ 93.3**	$ 98.3	$37.5	$(5.0)	(3.2%)	$60.8	106.8%
Gas Sales Margin	**$ 56.8**	$ 54.5	$19.4	$ 2.3	1.5%	$35.1	61.7%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues decreased $2.7 million, or 1.7%, in 2010 compared to 2009. Total Gas Operating Revenues include the recovery of the approved cost of sales, which are recorded as Purchased Gas and Conservation and Load Management (C&LM) in Operating Expenses. The decrease in Total Gas Operating Revenues in 2010 reflects lower Purchased Gas costs of $5.9 million partially offset by higher C&LM revenues of $0.9 million and higher sales margin of $2.3 million.

Purchased Gas and C&LM revenues decreased $5.0 million, or 3.2%, of Total Gas Operating Revenues in 2010 compared to 2009, primarily reflecting the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above, and lower sales of natural gas. Purchased Gas revenues include the recovery of the approved cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $2.3 million in 2010 compared to 2009, reflecting the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above. Absent the effect of this refund, natural gas sales margin decreased $2.6 million in 2010 compared to 2009, principally due to lower sales of natural gas, which reflect the effect of the milder winter heating season in the early part of 2010 compared to 2009.

Total Gas Operating Revenues increased $95.9 million, or 168.5%, in 2009 compared to 2008, reflecting the inclusion of Northern Utilities and Granite State for the full year in 2009. Total Gas Operating Revenues include the recovery of the approved cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The increase in Total Gas Operating Revenues in 2009 reflects higher Purchased Gas costs of $59.1 million, higher C&LM revenues of $1.7 million and higher sales margin of $35.1 million.

Natural gas sales margin increased $35.1 million in 2009 compared to 2008, reflecting the contribution to natural gas sales by Northern Utilities and Granite State. Natural gas sales margin also includes the unfavorable effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales—Unitil's total electric kWh sales increased 4.5% in 2010 compared to 2009. Electric kWh sales to residential customers and C&I customers increased 5.5% and 3.8%, respectively, in 2010 compared to 2009. The increased sales reflect higher than average summer temperatures in the Company's utility service territories in 2010 where there were approximately 61% more Cooling Degree

Days in the three month period ended September 30, 2010, compared to the prior year, coupled with an improving regional economy. According to ISO-New England, the grid operator for the New England region, July of 2010 was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month. On a weather-normalized basis, kWh sales in 2010 increased 1.6% compared to 2009.

Unitil's total electric kWh sales decreased 4.5% in 2009 compared to 2008. Electric kWh sales to residential customers and C&I customers decreased 2.2% and 6.1%, respectively, in 2009 compared to 2008. The lower electric kWh sales in 2009 compared to 2008 reflect lower average usage by our customers due to the continued regional economic slowdown and milder summer weather in 2009. Average summer temperatures in the Company's electric service territories, as measured by cooling degree days, were 31% cooler in 2009 compared to the same period in 2008 and were 26% cooler than normal.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (millions)				Change 2010 vs. 2009		Change 2009 vs. 2008	
	2010	2009	2008	kWh	%	kWh	%
Residential	**681.2**	645.9	660.2	35.3	5.5%	(14.3)	(2.2%)
Commercial / Industrial	**1,009.9**	972.9	1,035.7	37.0	3.8%	(62.8)	(6.1%)
Total	**1,691.1**	1,618.8	1,695.9	72.3	4.5%	(77.1)	(4.5%)

Electric Operating Revenues and Sales Margin—The following table details Total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenues (millions)

				Change 2010 vs. 2009		Change 2009 vs. 2008	
	2010	2009	2008	$	%(1)	$	%(1)
Electric Operating Revenue:							
Residential	**$108.5**	$108.9	$114.5	$ (0.4)	(0.2%)	$ (5.6)	(2.5%)
Commercial / Industrial	**95.2**	101.0	113.0	(5.8)	(2.7%)	(12.0)	(5.2%)
Total Electric Operating Revenue	**$203.7**	$209.9	$227.5	$ (6.2)	(2.9%)	$(17.6)	(7.7%)
Cost of Electric Sales:							
Purchased Electricity	**$137.7**	$151.6	$170.1	$(13.9)	(6.6%)	$(18.5)	(8.1%)
Conservation & Load Management	**6.0**	3.1	2.6	2.9	1.4%	0.5	0.2%
Total Cost of Electric Sales	**$143.7**	$154.7	$172.7	$(11.0)	(5.2%)	$(18.0)	(7.9%)
Electric Sales Margin	**$ 60.0**	$ 55.2	$ 54.8	$ 4.8	2.3%	$ 0.4	0.2%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues decreased by $6.2 million, or 2.9%, in 2010 compared to 2009. Total Electric Operating Revenues include the recovery of approved costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The net decrease in Total Electric Operating Revenues in 2010 reflects lower Purchased Electricity costs of $13.9 million offset by higher C&LM revenues of $2.9 million and higher sales margin of $4.8 million.

Purchased Electricity and C&LM revenues decreased $11.0 million, or 5.2%, of Total Electric Operating Revenues in 2010 compared to 2009, reflecting an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity costs, partially offset by higher spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the approved cost of energy efficiency and conservation programs. The Company recovers the approved cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $4.8 million in 2010 compared to 2009. The increase in electric sales margin reflects higher electric kWh sales and an electric rate increase, implemented in July 2010 for the Company's New Hampshire electric distribution utility.

Total Electric Operating Revenues decreased by $17.6 million, or 7.7%, in 2009 compared to 2008. Total Electric Operating Revenues include the recovery of approved costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The net decrease in Total Electric Operating Revenues in 2009 reflects lower Purchased Electricity costs of $18.5 million offset by higher C&LM revenues of $0.5 million and higher sales margin of $0.4 million.

Electric sales margin increased $0.4 million in 2009 compared to 2008. The increase in electric sales margin reflects higher rates offset by lower sales volumes. Total electric sales decreased 4.5% in 2009 compared to 2008, reflecting lower average usage by our customers due to the continued economic slowdown and milder summer weather in 2009.

Operating Revenue—Other

Total Other Revenue increased $0.3 million in 2010 compared to 2009 and $0.5 million in 2009 compared to 2008. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (millions)

				Change			
				2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$	%	$	%
Usource	**$4.6**	$4.3	$3.8	$0.3	7.0%	$0.5	13.2%
Total Other Revenue	**$4.6**	$4.3	$3.8	$0.3	7.0%	$0.5	13.2%

Operating Expenses

Purchased Gas—Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $5.9 million, or 6.1%, in 2010 compared to 2009. This increase reflects the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above. Absent the effect of this refund, Purchased Gas decreased $1.0 million in 2010 compared to 2009, principally due to lower sales of natural gas, which reflect the effect of the milder winter heating season in the early part of 2010 compared to 2009, partially offset by higher natural gas commodity prices in 2010. The Company recovers the approved costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in approved expenses do not affect earnings.

In 2009, Purchased Gas increased $59.1 million, or 158.4%, compared to 2008. This increase primarily reflects the inclusion of Northern Utilities for the full year in 2009.

Purchased Electricity—Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity decreased $13.9 million, or 9.2%, in 2010 compared to 2009. This decrease reflects an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity costs, partially offset by increased sales. The Company recovers the approved costs of Purchased Electricity in its rates at cost and therefore changes in approved expenses do not affect earnings.

In 2009, Purchased Electricity expenses decreased $18.5 million, or 10.9%, compared to 2008, reflecting lower sales volumes and lower electric commodity prices.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. Total O&M expenses increased $4.1 million, or 9.2%, in 2010 compared to 2009. The changes in O&M expenses reflect higher compensation and retiree employee benefit expenses of $2.7 million and higher utility operating costs of $1.4 million. Utility operating costs primarily consist of utility distribution and transmission system maintenance costs, bad debt expenses, office expenses and insurance costs. O&M expenses in 2010 reflect the full integration of Northern Utilities and Granite State into the Company's consolidated operating results.

In 2009, total O&M expense increased $17.2 million, or 62.5%, compared to 2008. The inclusion of Northern Utilities and Granite State for the full year in 2009 accounted for $8.8 million of the increase. In addition, higher compensation and retiree and employee benefit expenses of $2.2 million and net other utility operating costs of $0.4 million contributed to the increase in O&M expenses year over year. In 2009 the Company expensed professional fees of approximately $3.0 million related to regulatory and legal matters concerning the December 2008 ice storm. The increase in O&M expenses in 2009 over 2008 also reflects lower O&M recorded in 2008 due to the receipt of a $2.8 million insurance settlement in that year.

Conservation & Load Management—C&LM expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 65% of these costs are related to electric operations and 35% to gas operations.

Total Conservation & Load Management expenses increased by $3.8 million, in 2010 compared to 2009. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Total Conservation & Load Management expenses increased by $2.2 million in 2009 compared to 2008.

Depreciation and Amortization—Depreciation and Amortization expense increased $1.5 million, or 5.5% in 2010 compared to 2009. This increase reflects higher depreciation on normal utility plant additions partially offset by lower amortization expense in the current year.

In 2009, Depreciation and Amortization expense increased $8.3 million, or 43.5%, compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009 and higher depreciation on normal utility plant additions.

Local Property and Other Taxes—Local Property and Other Taxes increased $0.8 million, or 7.7%, in 2010 compared to 2009. This increase reflects higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

In 2009, Local Property and Other Taxes increased by $4.1 million, or 65.1%, compared to 2008. This increase primarily reflects the inclusion of Northern Utilities and Granite State for the full year in 2009, and higher local property tax rates on higher levels of utility plant in service.

Federal and State Income Taxes—Federal and State Income Taxes decreased by $0.9 million in 2010 compared to 2009 due to lower pre-tax operating income in 2010 compared to 2009 (See Note 8 to the accompanying Consolidated Financial Statements).

Federal and State Income Taxes increased by $0.8 million in 2009 compared to 2008 due to higher pre-tax operating income in 2009 compared to 2008 (See Note 8 to the accompanying Consolidated Financial Statements).

Other Non-operating Expenses (Income)—Other Non-operating Expenses (Income) was flat in 2010 compared to 2009 and in 2009 compared to 2008.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated (See Note 4 to the accompanying Consolidated Financial Statements).

Interest Expense, net increased $2.3 million in 2010 compared to 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in 2010.

In 2009, Total Interest Expense, net increased by $5.3 million compared to 2008. The increase was primarily due to the issuance of $90 million of long-term notes issued by Northern Utilities and Granite State in December 2008 to partially finance the acquisition and higher average borrowings during 2009, partially offset by increases in interest income on regulatory assets and Allowance for Funds Used During Construction (AFUDC) in 2009.

LIQUIDITY, COMMITMENTS AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

On March 2, 2010, both Unitil Energy and Northern Utilities closed long-term financings:

(i) Unitil Energy closed $15,000,000 of First Mortgage Bonds, through a private placement to institutional investors. The First Mortgage Bonds have a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

(ii) Northern Utilities closed $25,000,000 of Senior Unsecured Notes, through a private placement to institutional investors. The Senior Unsecured Notes have a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

The Company, along with its subsidiaries, are individually and collectively members of the Unitil Cash Pool (the Cash Pool). The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool allows for an efficient exchange of cash among the Company and its subsidiaries. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on actual interest costs from lenders under the Company's revolving credit facility. At December 31, 2010 and 2009, all of the Company's subsidiaries were in compliance with the regulatory requirements to participate in the Cash Pool.

Unitil has a revolving credit facility with a group of banks that extends to October 8, 2013. The borrowing limit under the revolving credit facility is $80.0 million. There was $66.8 million and $64.5 million in short-term debt outstanding through bank borrowings under the revolving credit facility at December 31, 2010 and 2009, respectively. The total amount of credit available under the Company's revolving credit facility was $13.2 million and $15.5 million at December 31, 2010 and 2009, respectively. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter. As of December 31, 2010 and 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

The continued availability of various methods of financing, as well as the choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of earnings, cash flows, financial position; and the competitive pricing offered by financing sources.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2010.

		Payments Due by Period			
Significant Contractual Obligations (millions) as of December 31, 2010	**Total**	**2011**	**2012-2013**	**2014-2015**	**2016 & Beyond**
Long-term Debt	$288.8	$ 0.5	$ 1.0	$ 6.5	$280.8
Interest on Long-term Debt	284.1	20.0	39.9	39.6	184.6
Gas Supply Contracts	276.0	43.5	74.0	68.0	90.5
Power Supply Contract Obligations	21.8	9.1	9.6	1.4	1.7
Other	5.6	2.0	2.4	0.9	0.3
Total Contractual Cash Obligations	$876.3	$75.1	$126.9	$116.4	$557.9

The Company and its subsidiaries have material energy supply commitments that are discussed in Note 6 to the accompanying Consolidated Financial Statements. Cash outlays for the purchase of electricity and natural gas to serve customers are subject to reconciling recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over-collected cash over subsequent periods of less than a year.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2010, there were approximately $36.3 million of guarantees outstanding and the longest term guarantee extends through December 31, 2012. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed below.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $11.7 million and $10.0 million outstanding at December 31, 2010 and 2009, respectively, related to these asset management agreements. The amount of natural gas inventory released in December 2010, which is payable in January 2011, is $3.9 million and recorded in Accounts Payable at December 31, 2010.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $3.8 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million.

Benefit Plan Funding

The Company, along with its subsidiaries, made cash contributions to its Pension Plan in the amount of $4.3 million and $4.2 million in 2010 and 2009, respectively. The Company, along with its subsidiaries, contributed $3.5 million and $2.8 million to Voluntary Employee Benefit Trusts (VEBT) in 2010 and 2009, respectively. The Company, along with its subsidiaries, expects to continue to make contributions to its

Pension Plan and the VEBT's in 2011 and future years at minimum required and discretionary funding levels consistent with the amounts recovered in the distribution utilities' rates for these other postretirement benefit costs. (See Note 10 to the accompanying Consolidated Financial Statements.)

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements. (See Note 4 to the accompanying Consolidated Financial Statements.)

Cash Flows

Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash for 2010 and 2009.

(millions)	2010	2009
Cash Provided by Operating Activities	**$25.9**	$50.9

Cash Provided by Operating Activities—Cash Provided by Operating Activities was $25.9 million in 2010, a decrease of ($25.0) million over the comparable period in 2009. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes, was $49.0 million in 2010 compared to $44.5 million in 2009, representing an increase of $4.5 million. Working capital changes in Current Assets and Liabilities resulted in a ($12.1) million net use of cash in 2010, compared to a $29.4 million net source of cash in 2009, representing a net increased use of cash of ($41.5) million primarily due to increased uses of cash in Accounts Receivable ($9.6) million, Accrued Revenue ($15.6) million, Refundable Taxes ($7.3) million, and Gas Inventory ($13.6 million). Deferred Regulatory and Other Charges resulted in a ($7.9) million use of cash in 2010, compared to a ($24.6) million use of cash in 2009. In 2010, Deferred Regulatory and Other Charges include an approximately ($7.4) million use of cash related to the funding of non-recurring deferred regulated charges related to the 2010 wind storm. In 2009, Deferred Regulatory and Other Charges include an approximately ($14.0) million use of cash related to the funding of non-recurring deferred regulated charges related to the 2008 Ice Storm. All Other, net operating activities resulted in a use of cash of ($3.1) million in 2010 compared to a source of cash of $1.6 million in 2009.

(millions)	2010	2009
Cash (Used in) Investing Activities	**$(49.6)**	$(65.6)

Cash (Used in) Investing Activities—Cash Used in Investing Activities was ($49.6) million for 2010 compared to ($65.6) million in 2009. Capital expenditures for property, plant and equipment additions were ($49.6) million in 2010 compared to ($58.7) million in 2009, representing a decreased use of cash of $9.1 million. Cash Used in Investing Activities in 2009 included ($6.9) million related to the Company's acquisition of Northern Utilities and Granite State. Capital expenditures are projected to be approximately ($57) million in 2011, primarily reflecting normal electric and gas utility system additions.

(millions)	2010	2009
Cash Provided by Financing Activities	**$24.9**	$10.9

Cash Provided by Financing Activities—Cash Provided by Financing Activities was $24.9 million in 2010 compared to $10.9 million in 2009. In 2010, sources of cash from financing activities included proceeds from issuance of long-term debt, net of $39.5 million, discussed above, proceeds from issuance of short-term debt of $2.3 million and the issuance of common stock of $0.9 million. Uses of cash included regular quarterly dividend payments on common and preferred stock of ($15.0) million, a decrease in gas inventory financing of ($2.2) million and all other financing activities which resulted in a use of ($0.6) million.

FINANCIAL COVENANTS AND RESTRICTIONS

The agreements under which the Company's and its subsidiaries' long-term debt were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations and covenants restricting the ability to (i) pay dividends, (ii) incur indebtedness and liens, (iii) merge or consolidate with another entity or (iv) sell, lease or otherwise dispose of all or substantially all assets. (See Note 4 to the accompanying Consolidated Financial Statements.)

The long-term debt and preferred stock of Unitil, Unitil Energy, Fitchburg, Northern Utilities, Granite State and Unitil Realty are privately held, and the Company does not issue commercial paper. For these reasons, the debt securities of Unitil and its subsidiaries are not publicly rated.

The Company's revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter.

The Company and its subsidiaries are currently in compliance with all such covenants in these debt instruments.

DIVIDENDS

Unitil's annualized common dividend was $1.38 per common share in 2010, 2009 and 2008. Unitil's dividend policy is reviewed periodically by the Board of Directors. Unitil has maintained an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2011 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

LEGAL PROCEEDINGS

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2011. The Company continues to believe the suit is without merit and will defend itself vigorously.

REGULATORY MATTERS

Overview (Unitil Energy, Fitchburg, and Northern Utilities)—Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territories at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern

Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next one to four years, is $46.8 million as of December 31, 2010 including $13.3 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Fitchburg—Base Rate Case Filings—On January 14, 2011, Fitchburg filed a petition with the MDPU requesting approval of a comprehensive revenue decoupling proposals and for an increase in its electric and gas distribution rates. The Company's revenue decoupling proposal is modeled closely on proposals already approved by the Department for other gas and electric utilities operating in the Commonwealth of Massachusetts and is intended to facilitate the achievement of important public policy objectives of fostering energy efficiency, conservation and protecting the environment. The proposed rates are scheduled to change in conjunction with the implementation of revenue decoupling and are subject to the review and approval of the MDPU.

In its rate filing the Company made a request for an increase of $7.1 million in its electric distribution rates, including the recovery of deferred emergency storm restoration costs. The Company also proposed a rate-impact mitigation alternative offset, in whole, the electric distribution rate increase with a corresponding decrease in its Transition Charge. The Transition Charge is the means by which Fitchburg recovers its power supply-related stranded costs and other restructuring-related regulatory assets, discussed above. Any offsetting decrease in the Transition Charge would allow for the recovery of the restructuring related stranded costs over an extended term. The Company's filing included a request for an increase of $4.4 million in its gas distribution rates. The MDPU issued an order suspending and deferring the use of the rates until August 2, 2011, pending an investigation and analysis of the Company's filing.

Granite State Gas Transmission, Inc.—Base Rate Case Filing—On June 29, 2010, Granite State filed a base transportation rate increase of $2.3 million in annual revenue with the FERC, which is Granite State's first request for a rate change since its last general rate case in 1997. On July 30, 2010, the FERC ordered the rate increase to be effective on January 1, 2011, subject to refund and hearing and settlement procedures. On November 30, 2010, a settlement was filed on behalf of Granite State and all intervenors in the proceeding, resolving all issues in the docket. The settlement provides for an increase of approximately $1.7 million in annual revenue, based on new gas transportation rates to be effective January 1, 2011. The settlement was approved by the FERC on January 31, 2011.

Unitil Energy Rate Case Filing—On April 15, 2010, Unitil Energy filed a proposed base rate increase of $10.1 million, an increase of 6.5 percent above present rates. In addition, Unitil Energy's filing also included a proposed long-term rate plan establishing future rate step adjustments for utility plant investments and enhanced reliability and vegetation management program expenditures. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy of $5.2 million (annual) effective July 1, 2010 which is being collected by a uniform per kilowatt-hour (kWh) surcharge of $0.00438 on each of Unitil Energy's current rate schedules. Once permanent rates are approved by the NHPUC, they

will be reconciled to the date temporary rates were ordered, July 1, 2010. The Company is currently engaged in settlement proceedings regarding the permanent rate level and a long-term rate plan. A hearing in this matter is scheduled for early February 2011.

Major Wind Storm—On February 25, 2010, a significant wind storm struck portions of the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including approximately 85% of the Unitil Energy's customers. The Company spent approximately $7.4 million for the repair and replacement of electric distribution systems damaged during the storm, including $1.5 million related to capital construction and $5.9 million which has been deferred as a regulatory asset. Unitil Energy, in its base rate case filing discussed above, has requested recovery in rates for the costs associated with the emergency repair of its electric distribution system for damage caused by this storm.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region. The Company spent approximately $24.0 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.6 million related to capital construction and $15.4 million which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. If the Company is unable to recover a significant amount of these deferred storm costs, or if the Company's recovery of these costs is significantly delayed, then the Company's financial condition or results of operations could be adversely affected.

On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. On September 24, 2010, the NHPUC issued its final order in this matter and closed its investigation, accepting the NHPUC Staff's report finding that Unitil Energy had acted reasonably.

On November 9, 2009, the NHPUC granted Unitil Energy's petition to defer and record as a regulatory asset costs associated with electric distribution system damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's pending base rate case. The order clarified that the issues of the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are to be reviewed in the rate case. As of December 31, 2010, Unitil Energy has deferred approximately $2.2 million associated with the repair of its electric distribution system for future recovery in rates.

On December 30, 2009, the MDPU approved Fitchburg's petition to defer and record as a regulatory asset costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. The order of approval made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and confirmed that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. As of December 31, 2010, Fitchburg has deferred approximately $13.2 million associated with the repair of its electric distribution system for future recovery in rates.

The MDPU conducted an investigation of Fitchburg's preparation for, and response to, the December 2008 Ice Storm during the first half of 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service, and ordered several remedial actions. First, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices. The management audit, which is being performed by Jacobs Consultancy, Inc., began in the fourth quarter of 2010. Second, the MDPU directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. All of these operational and capital improvements have either been completed or are being implemented, and remain subject to MDPU review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

Fitchburg—Electric Operations—On November 24, 2010, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery continues through a Transition Charge Surcharge of $0.00400 per kWh. Changes to the Pension/ PBOP Adjustment, Residential Assistance Adjustment Factor, and Net Metering Recovery Surcharge were proposed in other proceedings. The rates were approved effective January 1, 2011, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2009 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting regulations concerning the items required by House Bill 4329. On July 30, 2010, the MDPU approved Fitchburg's electric and gas Emergency Response Plans.

Fitchburg—Gas Operations—On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement order to the Massachusetts Supreme Judicial Court (SJC). Fitchburg believes that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. The Company filed its Initial brief in this matter on January 10, 2011. This appeal remains pending before the Massachusetts SJC.

Fitchburg—Other—On February 11, 2009, the Massachusetts SJC issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The Massachusetts SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Massachusetts SJC, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, special tariffs to allow the net metering of customer-owned renewable generation, and terms and conditions for purchasing supplier receivables. Three year energy efficiency investment plans, plans to establish smart grid pilot programs, and net metering tariffs have been approved by the MDPU. Proposals to purchase long-term contracts for renewable energy and terms and conditions for purchasing supplier receivables are under review in a separately designated docket.

On March 1, 2010, Fitchburg submitted its annual filing to the MDPU of the 2009 Service Quality Reports for both its gas and electric divisions. On October 20, 2010, the MDPU issued its order with respect to Fitchburg's gas division's Report and noted that Fitchburg met or exceeded its established benchmarks in all Service Quality measures, that Fitchburg's performance was consistent with the MDPU's Service

Quality Guidelines and Fitchburg's Service Quality plan. An order on Fitchburg's electric division's Service Quality plan has not yet been issued and the matter remains pending.

Unitil Energy—Other—In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources (DER). An order approving a settlement agreement for a time-of-use pilot program was issued on February 26, 2010. On June 11, 2010, the NHPUC issued an order on the remaining two proposed projects and cost recovery. The NHPUC denied one of the two projects, citing that the costs outweighed the benefits but found the other project to be in the public interest. On November 1, 2010 Unitil Energy filed adjustments to base distribution rates to collect actual costs associated with authorized DER projects. This matter remains pending.

On June 17, 2010, Unitil Energy made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2010, including reconciliation of prior year costs and revenues. On July 30, 2010, the NHPUC approved the rate filing and reconciliation.

Northern Utilities—On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation (NOPVs) of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's consolidated balance sheet at December 31, 2010 was $0.7 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in portions of Northern Utilities' Maine service areas. In an order issued on July 30, 2010, the MPUC approved a Settlement Agreement resolving this matter, filed on behalf of Northern Utilities, the Maine Office of the Public Advocate, and several state legislator intervenors, which was filed with the MPUC on July 6, 2010. Under the Agreement, Northern Utilities will proceed with a comprehensive upgrade and replacement program (the Program), which will provide for the systematic replacement of cast iron, wrought iron and bare steel pipe in Northern Utilities' natural gas distribution system in Portland and Westbrook, Maine and the conversion of the system to intermediate pressure. The Agreement establishes the objective of completing the Program by the end of the 2024 construction season. Under the Agreement, the parties agreed to support a cost recovery mechanism that will provide for the timely recovery of prudently-incurred costs of the Program. The features of this cost recovery mechanism will be finalized during Northern Utilities' next base rate case proceeding, which is anticipated to be filed in early 2011.

ENVIRONMENTAL MATTERS

Unitil's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed. Also, see Note 6 to the accompanying consolidated financial statements.

Fitchburg recovers the environmental response costs incurred at this former MGP site in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. In January 2011, Fitchburg settled with the remaining insurance carriers for approximately $2.0 million and expects to receive these payments in the first quarter of 2011. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are shared equally between Fitchburg and its gas customers.

Northern Utilities' Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Also, see Part II, Item 7 below for Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Matters and Note 6 to the accompanying Consolidated Financial Statements for additional information on Environmental Matters.

EMPLOYEES AND EMPLOYEE RELATIONS

As of December 31, 2010, the Company and its subsidiaries had 437 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of December 31, 2010, 150 of the Company's employees were represented by labor unions. These employees are covered by four separate collective bargaining agreements which expire on March 31, 2012, May 31, 2012, May 31, 2013 and June 5, 2014. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to negotiate new agreements prior to their expiration dates.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the Financial Accounting Standards Board Accounting Standards Codification (FASB Codification). In accordance with the FASB Codification, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The FASB Codification specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets." If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities."

The Company's principal regulatory assets and liabilities are included on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided in Note 1 thereto. The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements.

The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The FASB Codification requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's RBO and reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2010 and 2009, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000 and $300,000, respectively, in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2010 and 2009, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $728,000 and $735,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $565,000 and $576,000, respectively. (See Note 10 to the accompanying Consolidated Financial Statements).

Income Taxes—The Company is subject to Federal and State income taxes as well as various other business taxes. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes.

Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining the current and deferred tax assets and liabilities. The Company's current and deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. Periodically, the Company assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Depreciation—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2010, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements" in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 8, "Income Taxes," Note 5, "Energy Supply," Note 10, "Retirement Benefit Plans," and Note 6, "Commitment and Contingencies," to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please also refer to Item 1A. "Risk Factors".

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on short-term borrowings was 2.3%, 3.4%, and 3.8% during 2010, 2009, and 2008, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Unitil Corporation and subsidiaries:

We have audited the accompanying consolidated balance sheet of Unitil Corporation and subsidiaries (the Company) as of December 31, 2010, and the related consolidated statements of earnings, cash flows and changes in common stock equity for the year then ended. We also have audited Unitil Corporation and subsidiaries' internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that *(a)* pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; *(b)* provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and *(c)* provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Unitil Corporation and subsidiaries as of December 31, 2010, and the consolidated results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Unitil Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ McGladrey & Pullen, LLP
Boston, Massachusetts
February 3, 2011

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Unitil Corporation and subsidiaries:

We have audited the accompanying consolidated balance sheet of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the years ended December 31, 2009 and 2008. The Company's management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unitil Corporation and subsidiaries as of December 31, 2009, and the consolidated results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

/s/ Caturano and Company, Inc.
Boston, Massachusetts
February 10, 2010

CONSOLIDATED STATEMENTS OF EARNINGS

(Millions, except common shares and per share data)

Year Ended December 31,	2010	2009	2008
Operating Revenues:			
Gas	**$ 150.1**	$152.8	$ 56.9
Electric	**203.7**	209.9	227.5
Other	**4.6**	4.3	3.8
Total Operating Revenues	**358.4**	367.0	288.2
Operating Expenses:			
Purchased Gas	**90.5**	96.4	37.3
Purchased Electricity	**137.7**	151.6	170.1
Operation and Maintenance	**48.8**	44.7	27.5
Conservation & Load Management	**8.8**	5.0	2.8
Depreciation and Amortization	**28.9**	27.4	19.1
Provisions for Taxes:			
Local Property and Other	**11.2**	10.4	6.3
Federal and State Income	**4.5**	5.4	4.6
Total Operating Expenses	**330.4**	340.9	267.7
Operating Income	**28.0**	26.1	20.5
Other Non-Operating Expenses	**0.3**	0.3	0.3
Income Before Interest Expense	**27.7**	25.8	20.2
Interest Expense, net	**18.1**	15.8	10.5
Net Income	**9.6**	10.0	9.7
Less Dividends on Preferred Stock	**0.1**	0.1	0.1
Earnings Applicable to Common Shareholders	**$ 9.5**	$ 9.9	$ 9.6
Average Common Shares Outstanding (000's)—Basic	**10,823**	9,647	5,830
Average Common Shares Outstanding (000's)—Diluted	**10,824**	9,647	5,830
Earnings per Common Share—Basic and Diluted	**$ 0.88**	$ 1.03	$ 1.65

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS *(Millions)*

ASSETS

December 31,	2010	2009
Utility Plant:		
Electric	**$321.5**	$302.3
Gas	**360.1**	325.5
Common	**30.2**	28.9
Construction Work in Progress	**16.6**	26.0
Utility Plant	**728.4**	682.7
Less: Accumulated Depreciation	**251.9**	233.0
Net Utility Plant	**476.5**	449.7
Current Assets:		
Cash	**8.9**	7.7
Accounts Receivable, net	**36.9**	33.5
Accrued Revenue	**46.7**	44.0
Refundable Taxes	**7.5**	1.7
Gas Inventory	**10.6**	14.3
Material and Supplies	**2.9**	2.6
Prepayments and Other	**3.6**	3.0
Total Current Assets	**117.1**	106.8
Noncurrent Assets:		
Regulatory Assets	**143.0**	144.5
Other Noncurrent Assets	**23.0**	24.2
Total Noncurrent Assets	**166.0**	168.7
TOTAL ASSETS	**$759.6**	$725.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED BALANCE SHEETS (cont.) *(Millions)*

CAPITALIZATION AND LIABILITIES

December 31,	2010	2009
Capitalization:		
Common Stock Equity	**$189.0**	$193.1
Preferred Stock	**2.0**	2.0
Long-Term Debt, Less Current Portion	**288.3**	248.9
Total Capitalization	**479.3**	444.0
Current Liabilities:		
Long-Term Debt, Current Portion	**0.5**	0.4
Accounts Payable	**26.5**	25.1
Short-Term Debt	**66.8**	64.5
Energy Supply Contract Obligations	**17.0**	23.1
Other Current Liabilities	**16.1**	16.6
Total Current Liabilities	**126.9**	129.7
Deferred Income Taxes	**43.8**	39.8
Noncurrent Liabilities:		
Energy Supply Contract Obligations	**12.6**	21.7
Retirement Benefit Obligations	**74.0**	65.5
Environmental Obligations	**14.5**	14.3
Other Noncurrent Liabilities	**8.5**	10.2
Total Noncurrent Liabilities	**109.6**	111.7
TOTAL CAPITALIZATION AND LIABILITIES	**$759.6**	$725.2

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS *(Millions)*

Year Ended December 31,	2010	2009	2008
Operating Activities:			
Net Income	**$ 9.6**	$ 10.0	$ 9.7
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**28.9**	27.4	19.1
Deferred Taxes Provision	**10.5**	7.1	7.4
Changes in Working Capital Items:			
Accounts Receivable	**(3.4)**	6.2	(6.4)
Accrued Revenue	**(2.7)**	12.9	(10.3)
Refundable Taxes	**(5.8)**	1.5	(2.5)
Gas Inventory	**3.7**	17.3	—
Accounts Payable	**1.4**	(3.4)	11.4
Other Changes in Working Capital Items	**(5.3)**	(5.1)	7.1
Deferred Regulatory and Other Charges	**(7.9)**	(24.6)	2.6
Other, net	**(3.1)**	1.6	9.2
Cash Provided by Operating Activities	**25.9**	50.9	47.3
Investing Activities:			
Property, Plant and Equipment Additions	**(49.6)**	(58.7)	(28.3)
Acquisitions, net (See Note 2)	**—**	(6.9)	(209.9)
Cash (Used In) Investing Activities	**(49.6)**	(65.6)	(238.2)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt, net	**2.3**	(9.6)	55.3
Proceeds from Issuance (Repayment) of Long-Term Debt, net	**39.5**	(0.4)	89.6
Net Increase (Decrease) in Gas Inventory Financing	**(2.2)**	(21.8)	24.0
Dividends Paid	**(15.0)**	(13.2)	(8.0)
Proceeds from Issuance of Common Stock	**0.9**	56.4	37.4
Other, net	**(0.6)**	(0.5)	(0.5)
Cash Provided by Financing Activities	**24.9**	10.9	197.8
Net Increase (Decrease) in Cash	**1.2**	(3.8)	6.9
Cash at Beginning of Year	**7.7**	11.5	4.6
Cash at End of Year	**$ 8.9**	$ 7.7	$ 11.5
Supplemental Information:			
Interest Paid	**$ 20.5**	$ 19.3	$ 12.5
Income Taxes Paid (Refunded)	**$ 2.3**	$ (3.8)	$ (0.5)

(The accompanying Notes are an integral part of these consolidated financial statements.)

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2008	$ 65.3	$ 35.1	**$100.4**
Net Income for 2008		9.7	**9.7**
Dividends		(8.0)	**(8.0)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 32,754 Common Shares	0.8		**0.8**
Issuance of 2,000,000 Common Shares (See Note 3)	36.2		**36.2**
Balance at December 31, 2008	102.7	36.8	**139.5**
Net Income for 2009		10.0	**10.0**
Dividends		(13.2)	**(13.2)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 43,615 Common Shares	0.9		**0.9**
Issuance of 2,970,000 Common Shares (See Note 3)	55.5		**55.5**
Balance at December 31, 2009	159.5	33.6	**193.1**
Net Income for 2010		9.6	**9.6**
Dividends		(15.0)	**(15.0)**
Shares Issued Under Stock Plans	0.4		**0.4**
Issuance of 41,455 Common Shares	0.9		**0.9**
Balance at December 31, 2010	$160.8	$ 28.2	**$189.0**

(The accompanying Notes are an integral part of these consolidated financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource). Bay State is a wholly-owned subsidiary of NiSource.

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in all reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the "distribution utilities").

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—The Company's consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation. The operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from December 1, 2008 through December 31, 2010.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the Massachusetts Department of Public Utilities (MDPU), Unitil Energy is regulated by the New Hampshire Public Utilities Commission (NHPUC) and Northern Utilities is regulated by the Maine Public Utilities Commission (MPUC) and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the Financial Accounting Standards Board Accounting Standards Codification (FASB Codification). The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

	December 31,	
Regulatory Assets consist of the following (millions)	**2010**	**2009**
Energy Supply Contract Obligations	**$ 21.7**	$ 34.7
Deferred Restructuring Costs	**25.0**	28.3
Subtotal—Restructuring Related Items	**46.7**	63.0
Retirement Benefit Obligations	**47.1**	43.7
Income Taxes	**12.7**	14.5
Environmental Obligations	**20.3**	22.7
Deferred Storm Charges	**21.0**	14.6
Other	**10.9**	7.9
Total Regulatory Assets	**$158.7**	$166.4
Less: Current Portion of Regulatory Assets [1]	**15.7**	21.9
Regulatory Assets—noncurrent	**$143.0**	$144.5

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. Under the Independent System Operator—New England (ISO-NE) Financial Assurance Policy (Policy), Unitil's affiliates Unitil Energy, Fitchburg and Unitil Power are required to provide assurance of their ability to satisfy their obligations to ISO-NE. Under this Policy, Unitil's affiliates provide cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2010 and 2009, the Unitil affiliates had deposited $7.0 million and

$4.5 million, respectively to satisfy their ISO-NE obligations. In addition, Northern Utilities has cash margin deposits to satisfy requirements for its natural gas hedging program. On December 31, 2010 and 2009, there was $1.5 million and $2.9 million, respectively, deposited for this purpose.

Goodwill and Intangible Assets—As a result of the acquisitions of Northern Utilities and Granite State, the Company recognized a bargain purchase adjustment as a reduction to Utility Plant, to be amortized over a ten year period, beginning with the date of the Acquisitions, as authorized by regulators. (See Note 2).

Off-Balance Sheet Arrangements—As of December 31, 2010, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office equipment, vehicles and other equipment under operating leases (See Note 4).

Derivatives—The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases natural gas futures contracts on the New York Mercantile Exchange (NYMEX) that correspond to the associated delivery month. Any gains or losses resulting from the change in the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company records gains and losses resulting from the change in fair value of the derivatives as regulatory liabilities or assets, then reclassifies these gains or losses into Purchased Gas when the gains and losses are passed through to customers in accordance with rate reconciling mechanisms.

As of December 31, 2010 and December 31, 2009, the Company had 1.3 billion and 1.9 billion cubic feet (BCF), respectively, outstanding in natural gas purchase contracts under its hedging program.

The tables below show derivatives, which are part of the regulatory approved hedging program, that are not designated as hedging instruments, under FASB ASC 815-20. As discussed above, the change in fair value related to these derivatives is recorded initially as a Regulatory Asset then reclassified to Purchased Gas in accordance with the recovery mechanism. The tables below include disclosure of the Regulatory Asset and reclassifications from the Regulatory Asset into Purchased Gas.

Fair Value Amount (millions) Offset in Regulatory Assets (1), as of:

		Fair Value	
Description	**Balance Sheet Location**	**December 31, 2010**	**December 31, 2009**
Natural Gas Futures Contracts	Other Current Liabilities	$0.8	$2.2
Natural Gas Futures Contracts	Other Noncurrent Liabilities	0.2	0.1
Total		$1.0	$2.3

(1) The current portion of Regulatory Assets are recorded as Accrued Revenue on the Company's Consolidated Balance Sheets.

	Twelve Months Ended December 31,	
(millions)	**2010**	**2009**
Amount of (Gain)/Loss Recognized in Regulatory Assets for Derivatives:		
Natural Gas Futures Contracts	$3.9	$5.9
Amount of Loss Reclassified into Consolidated Statements of Earnings (2):		
Purchased Gas	$5.2	$9.3

(2) These amounts are offset in the Consolidated Statements of Earnings with the recognition of accrued revenue as a component of Gas Operating Revenue and therefore there is no effect on earnings.

Utility Revenue Recognition—Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition—Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Doubtful Accounts—The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company.

Retirement Benefit Obligations—The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates. (See Note 10.)

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2010, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below. (See Note 6).

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 2.25%, 3.24% and 4.58% in 2010, 2009 and 2008, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At

December 31, 2010 and 2009, the Company estimates that the negative salvage value of future retirements recorded on the consolidated balance sheet in Accumulated Depreciation is $35.5 million and $37.2 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2010 – 3.99%, 2009 – 4.02% and 2008 – 3.94%.

Gas Inventory—The weighted average cost methodology is used to value natural gas in storage.

Environmental Matters—The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has or will recover substantially all of the costs of the environmental remediation work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 6, Commitments and Contingencies. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation using the fair value-based method (See Note 3).

Sales and Consumption Taxes—The Company bills its customers sales tax in Massachusetts and Maine and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

Income Taxes—The Company is subject to Federal and State income taxes as well as various other business taxes. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes.

Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining the current and deferred tax assets and liabilities. The Company's current and deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. Periodically, the Company assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Dividends—The Company's dividend policy is reviewed periodically by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors. For the years ended December 31, 2010, 2009 and 2008, the Company paid a dividend at an annual rate of $1.38 per common share.

Other Recently Issued Pronouncements—There are no recently issued pronouncements that the Company has not already adopted.

Subsequent Events—The Company evaluates all events or transactions through the date of the related filing. During the period for this filing, the Company did not have any material subsequent events that impacted its consolidated financial statements.

Reclassifications—Certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation.

Note 2: Acquisitions

On December 1, 2008, the Company purchased (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource pursuant to the Stock Purchase Agreement (SPA) dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil. The aggregate purchase price for the Acquisitions was $209.2 million, comprised of $160 million in cash, plus an additional working capital adjustment of $49.2 million. The largest component of working capital was approximately $30.0 million of natural gas storage inventory.

The Company accounted for the Acquisitions under the purchase method of accounting for business combinations, in accordance with FASB Statement No. 141, "Business Combinations" ("SFAS No. 141") and the FASB Codification on business combinations. As the fair value of the net assets acquired exceeded the purchase price, the Company recognized a bargain purchase price (Plant Acquisition Adjustment or PAA) at December 1, 2008. The bargain purchase amount was recorded as a reduction of Utility Plant on the Company's Consolidated Balance Sheet and in accordance with regulatory settlements, is being amortized over ten years.

In accordance with settlement agreements between the Company, the NHPUC and the MPUC regarding the Acquisitions, the Company has agreed (i) not to seek recovery of transaction and transition costs in rates and (ii) for regulatory accounting purposes, to amortize, over a ten year period, the transaction and transition costs co-terminus with the Plant Acquisition Adjustment.

Note 3: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow:

Common Stock

The Company's common stock trades under the symbol, "UTL".

The Company had 10,890,262, and 10,836,759 of common shares outstanding at December 31, 2010 and December 31, 2009, respectively.

Unitil Corporation Common Stock Offering—On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2008 Offering). As part of this 2008 common stock offering, the underwriters exercised an over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the 2008 Offering including the over-allotment were approximately $41.9 million. On May 27, 2009, the Company issued and sold 2,400,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2009 Offering). As part of the 2009 Offering, the underwriters exercised an over-allotment option and purchased an additional 300,000 shares of the Company's common stock in June 2009. The Company's net increase to Common Equity and Cash proceeds from the 2009 Offering including the over-allotment were approximately $51.2 million. The combined total net increase to Common Equity and Cash proceeds from the 2008 Offering and 2009 Offering of $93.1 million (after payment of underwriting discount, but excluding offering expenses) were used to (i) repay all amounts outstanding under the bank credit facility that the Company used to partially finance the acquisition of Northern Utilities and Granite State which closed on December 1, 2008, and related transaction costs and expenses and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt.

Dividend Reinvestment and Stock Purchase Plan—During 2010, the Company sold 41,455 shares of its common stock, at an average price of $21.88 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans resulting in net proceeds of $0.9 million. The DRP provides participants in the plan a method for investing cash dividends on the Company's common stock and cash payments in additional shares of the Company's common stock. During 2009 and 2008, the Company raised $0.9 million and $0.8 million, respectively, of additional common equity through the issuance of 43,615 and 32,754 shares, respectively, of its common stock in connection with its DRP and 401(k) plans.

Shares Repurchased, Cancelled and Retired—During 2010, 2009 and 2008, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. The Company accounts for its stock-based compensation plans in accordance with the provisions of the FASB Codification and recognizes compensation costs at fair value at the date of grant. Details of the plans are as follows:

Restricted Stock Plan—The Company has a Restricted Stock Plan (the Plan). Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company common stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided for in the Plan. Awards fully vest over a period of four years at a rate of 25% each year.

During the vesting period, dividends on restricted shares underlying the award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit.

Restricted shares issued for 2008 – 2010 in conjunction with the Plan are presented in the following table:

Issuance Date	Shares	Aggregate Market Value (millions)
2/6/08	15,540	$0.4
2/17/09	32,260	$0.7
2/5/10	12,520	$0.3

The compensation expense associated with the issuance of shares under the Plan is being recorded over the vesting period and was $0.5 million, $0.7 million and $0.5 million in 2010, 2009 and 2008, respectively. There were 29,521 and 33,727 non-vested shares under the Plan as of December 31, 2010 and 2009, respectively. The weighted average grant date fair value of these shares was $21.77 and $22.68, respectively. At December 31, 2010, there was approximately $0.8 million of total unrecognized compensation cost under the Plan which is expected to be recognized over approximately 2.5 years. There were 472 restricted shares forfeited under the Plan during 2010. There were no cancellations under the Plan during 2010.

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998 and was terminated by the Board of Directors on January 16, 2003. The number of shares granted under this plan, as well as the terms and conditions of each grant, were determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options that were granted under this plan vested over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of the plan, key employees were granted options to purchase the Company's common stock at no less than 100% of the market price on the date the option is granted. All options had to be exercised no later than 10 years after the date on which they were granted.

There was no compensation expense associated with this plan in 2010, 2009 and 2008. The plan has remained in effect solely for the purposes of the continued administration of any options outstanding under the plan. No further grants of options have been made under this plan since it was terminated by the Board of Directors in 2003. As of December 31, 2010, 2009 and 2008, there was no aggregate intrinsic value of the options exercisable.

	2010		2009		2008	
	Number of Shares	**Average Exercise Price**	**Number of Shares**	**Average Exercise Price**	**Number of Shares**	**Average Exercise Price**
Beginning Options Outstanding	**63,500**	**$28.90**	97,200	$27.16	107,000	$27.13
Options Granted	**—**	**—**	—	—	—	—
Options Exercised	**—**	**—**	—	—	(3,300)	$24.51
Options Forfeited/Expired	**(30,500)**	**$32.17**	(33,700)	$23.88	(6,500)	$27.99
Ending Options Outstanding	**33,000**	**$25.88**	63,500	$28.90	97,200	$27.16
Options Vested and Exercisable-end of year	**33,000**	**$25.88**	63,500	$28.90	97,200	$27.16

The following summarizes certain data for the options outstanding at December 31, 2010:

Range of Exercise Prices	**Options Vested, Exercisable and Outstanding**	**Weighted Average Exercise Price**	**Remaining Contractual Life**
$25.00-$29.99	33,000	$25.88	0.1 years

The remaining 33,000 options outstanding under the Plan at December 31, 2010 expired without being exercised.

Preferred Stock

Two of Unitil's distribution companies, Unitil Energy and Fitchburg, have $2.0 million of preferred stock outstanding. At December 31, 2010, Unitil Energy has $0.2 million of 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and Fitchburg has two series of Redeemable, Cumulative Preferred Stock outstanding, $0.8 million of 5.125% Series and $1.0 million of 8.00% Series.

Fitchburg is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, Fitchburg may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2010, 2009 and 2008 related to the annual redemption offer were $25,000, $26,000 and $21,200, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2010 is $117,000 per year.

Earnings Per Share

The following table reconciles basic and diluted earnings per share.

(Millions except shares and per share data)	**2010**	**2009**	**2008**
Earnings Available to Common Shareholders	**$ 9.5**	$ 9.9	$ 9.6
Weighted Average Common Shares Outstanding—Basic (000's)	**10,823**	9,647	5,830
Plus: Diluted Effect of Incremental Shares (000's)	**1**	—	—
Weighted Average Common Shares Outstanding—Diluted (000's)	**10,824**	9,647	5,830
Earnings per Share—Basic and Diluted	**$ 0.88**	$ 1.03	$ 1.65

Weighted average options to purchase 33,000, 63,500 and 97,200 shares of common stock were outstanding during 2010, 2009 and 2008, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Additionally, 6,164, 28,963 and 15,985 weighted average non-vested restricted shares for 2010, 2009 and 2008, respectively, were not included in the above computation because the effect would have been antidilutive.

Note 4: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowings under its revolving credit facility. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery, vehicles and office equipment. Details regarding long-term debt, short-term debt and leases follow:

Long-Term Debt and Interest Expense

Long-Term Debt Structure and Covenants—The agreements under which the long-term debt of Unitil and its utility subsidiaries, Unitil Energy, Fitchburg, Northern Utilities, and Granite State, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

The long-term debt of Unitil is issued under Unsecured Promissory Notes with negative pledge provisions. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Unitil to issue new long-term debt, the covenants of the existing long-term agreement(s) must be satisfied, including that Unitil have total funded indebtedness less than 70% of total capitalization, and earnings available for interest equal to at least two times the interest charges for funded indebtedness. Each future senior long-term debt issuance of Unitil will rank pari passu with all other senior unsecured long-term debt issuances. The Unitil agreement requires that if Unitil defaults on any other future long-term debt agreement(s), it would constitute a default under its present long-term debt agreement. Furthermore, the default provisions are triggered by the defaults of Unitil Energy and Fitchburg or certain other actions against subsidiary companies in the Unitil System.

Substantially all of the property of Unitil Energy is subject to liens of indenture under which First Mortgage Bonds (FMB) have been issued. In order to issue new FMB, the customary covenants of the existing Unitil Energy Indenture Agreement must be met, including that Unitil Energy have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Unitil Energy agreements further require that if Unitil Energy defaults on any Unitil Energy FMB, it would constitute a default for all Unitil Energy FMB. The Unitil Energy default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

All of the long-term debt of Fitchburg, Northern Utilities and Granite State are issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of long-term debt ranks pari passu with its other senior unsecured long-term debt within that subsidiary. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for Fitchburg, Northern Utilities or Granite State to issue new long-term debt, the covenants of the existing long-term agreements of that subsidiary must be satisfied, including that the subsidiary have total funded indebtedness less than 65% of total capitalization. Additionally, to issue new long-term debt, Fitchburg must maintain earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Unitil Energy agreements, the Fitchburg, Northern Utilities and Granite State agreements each require that if that subsidiary defaults on any of its own long-term debt agreements, it would constitute a default under all of that subsidiary's long-term debt agreements. Each of the Fitchburg, Northern Utilities and Granite State default provisions are not triggered by the actions or defaults of Unitil or any of its other subsidiaries.

The Unitil, Unitil Energy, Fitchburg, Northern Utilities and Granite State long-term debt instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets. The Granite State notes are guaranteed by Unitil for the payment of principal, interest and other amounts payable. This guarantee will terminate if Granite State is reorganized and merges with and into Northern Utilities.

At December 31, 2010, there were no restrictions on Unitil's Retained Earnings for the payment of common dividends. Unitil Energy, Fitchburg, Northern Utilities and Granite State pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil's common shareholders.

Debt Repayment and Sinking Funds—The total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $426,643, $393,946, and $363,755 in 2010, 2009, and 2008, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2010 is: 2011 – $462,055; 2012 – $500,405; 2013 – $541,938; and 2014 – $2,486,919; and 2015 – 4,035,633, respectively.

Long-Term Debt Issuances

On March 2, 2010, both Unitil Energy and Northern Utilities closed long-term financings:

(i) Unitil Energy closed $15,000,000 of First Mortgage Bonds, through a private placement marketing process to institutional investors. The First Mortgage Bonds have a coupon rate of 5.24% and have a final maturity of ten years. Unitil Energy used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

(ii) Northern Utilities closed $25,000,000 of Senior Unsecured Notes, through a private placement marketing process to institutional investors. The Senior Unsecured Notes have a coupon rate of 5.29% and have a final maturity of ten years. Northern Utilities used the net proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

Fair Value of Long-Term Debt—Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements. If there were an active market for the Company's debt securities, the fair value of the Company's long-term debt would be estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield for December 2010. The carrying value of the Company's long-term debt at December 31, 2010 is $288.8 million. The fair value of the Company's long-term debt at December 31, 2010 is estimated to be approximately $313.8 million. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

Details on long-term debt at December 31, 2010 and 2009 are shown below:

Long-Term Debt (millions)	December 31, 2010	December 31, 2009
Unitil Corporation Senior Notes:		
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0
Unitil Energy First Mortgage Bonds:		
5.24% Series, Due March 2, 2020	**15.0**	—
8.49% Series, Due October 14, 2024	**15.0**	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0
Fitchburg Long-Term Notes:		
6.75% Notes, Due November 30, 2023	**19.0**	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0
Northern Utilities Senior Notes:		
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	30.0
5.29% Senior Notes, Due March 2, 2020	**25.0**	—
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	50.0
Granite State Senior Notes:		
7.15% Senior Notes, Due December 15, 2018	**10.0**	10.0
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**3.8**	4.3
Total Long-Term Debt	**288.8**	249.3
Less: Current Portion	**0.5**	0.4
Total Long-Term Debt, Less Current Portion	**$288.3**	$248.9

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Consistent with regulatory precedent, interest income is recorded on an under-collection of costs, including carrying charges of $0.9 million and $1.1 million in 2010 and 2009, respectively, on deferred storm costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (millions)

	2010	2009	2008
Interest Expense			
Long-term Debt	**$20.0**	$18.2	$12.0
Short-term Debt	**1.7**	2.1	1.3
Regulatory Liabilities	**0.3**	0.3	0.1
Subtotal Interest Expense	**22.0**	20.6	13.4
Interest Income			
Regulatory Assets	**(3.5)**	(3.6)	(2.5)
AFUDC [1] and Other	**(0.4)**	(1.2)	(0.4)
Subtotal Interest Income	**(3.9)**	(4.8)	(2.9)
Total Interest Expense, net	**$18.1**	$15.8	$10.5

(1) AFUDC—Allowance for Funds Used During Construction

Credit Arrangements

Unitil has a revolving credit facility with a group of banks that extends to October 8, 2013. The borrowing limit under the revolving credit facility is $80.0 million. There was $66.8 million and $64.5 million in short-term debt outstanding through bank borrowings under the revolving credit facility at December 31, 2010 and December 31, 2009, respectively. The total amount of credit available under the Company's revolving credit facility was $13.2 million and $15.5 million at December 31, 2010 and December 31, 2009, respectively. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter. As of December 31, 2010 and December 31, 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 8, 2010, the Company entered into the Fourth Amendment Agreement with Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto (the "Fourth Amendment Agreement"), further amending the credit agreement dated as of November 26, 2008 among Unitil, Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto. The credit agreement was previously amended on January 2, 2009, March 16, 2009, and October 13, 2009 to, among other things, increase the maximum borrowings under the facility to $80.0 million. The Fourth Amendment Agreement extends the scheduled termination date of the credit agreement to October 8, 2013 and provides for two conditional one-year extensions subsequent to the October 8, 2013 termination date (if agreed to among the lenders and Unitil). The Fourth Amendment Agreement also provides the Company a mechanism to request an increase in maximum borrowings of $20.0 million (in increments of not less than $5.0 million). The Fourth Amendment Agreement also provides a new letter of credit sub-facility pursuant to which up to $25.0 million of the credit agreement may be used for the purpose of issuing letters of credit for Unitil or its subsidiaries.

The weighted average interest rates on all short-term borrowings were 2.3%, 3.4%, and 3.8% during 2010, 2009, and 2008, respectively.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $11.7 million and $10.0 million outstanding at December 31, 2010 and December 31, 2009, respectively, related to these asset management agreements. The amount of natural gas inventory released in December 2010, which is payable in January 2011, is $3.9 million and recorded in Accounts Payable at December 31, 2010.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2010, 2009 and 2008 amounted to $1.0 million, $1.0 million and $0.6 million respectively. Fitchburg leases its operations facility in Fitchburg, Massachusetts under an operating lease, with a primary term through January 31, 2013. The lease agreement allows for three additional five-year renewal periods at the option of Fitchburg.

The following is a schedule of future operating lease payment obligations and future minimum lease payments under capital leases as of December 31, 2010:

Year Ending December 31, (000's)	Operating Leases	Capital Leases
2011	$1,178	$ 780
2012	1,086	469
2013	727	154
2014	484	60
2015	362	35
2016 – 2020	289	2
Total Payments	**$4,126**	**$1,500**

Guarantees

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2010, there were approximately $36.3 million of guarantees outstanding and the longest term guarantee extends through December 31, 2012. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage management agreement, discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of December 31, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $3.8 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Note 5: Energy Supply

Natural Gas Supply

Unitil manages gas supply for customers served by Northern Utilities in Maine and New Hampshire as well as customers served by Fitchburg in Massachusetts.

Fitchburg's residential and C&I customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors. Many large and some medium C&I customers purchase their supplies from third-party suppliers, while most of Fitchburg's residential and small C&I customers continue to purchase their supplies at regulated rates from Fitchburg. Northern Utilities' C&I natural gas customers have the opportunity to purchase their natural gas supply from third-party gas supply vendors, and third-party supply is prevalent among Northern Utilities' larger C&I customers. Most small C&I customers, as well as all residential customers, purchase their gas supply from Northern Utilities under regulated rates and tariffs. The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

Regulated Natural Gas Supply

Fitchburg purchases natural gas under contracts of one year or less, as well as from producers and marketers on the spot market. Fitchburg arranges for gas delivery to its system through its own long-term contracts with Tennessee Gas Pipeline, or in the case of liquefied natural gas (LNG) or liquefied propane gas (LPG), to truck supplies to each storage facility within Fitchburg's service territory.

Fitchburg has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, Fitchburg owns a propane air gas plant and a LNG storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Northern Utilities purchases a majority of its natural gas from U.S. domestic and Canadian suppliers under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern Utilities arranges for gas delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of LNG, to truck supplies to each storage facility within Northern Utilities' service territory.

Northern Utilities has available under firm contract 100,000 MMbtu per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.4 Bcf of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns an LNG storage and vaporization facility. This plant is used principally during peak load periods to augment the supply of pipeline natural gas.

Electric Power Supply

The restructuring of the utility industry in New Hampshire required the divestiture of Unitil's power supply arrangements and the procurement of replacement supplies, which provided the flexibility for migration of customers to and from utility energy service. Fitchburg, Unitil Energy, and Unitil Power each are members of the New England Power Pool (NEPOOL) and participate in the ISO New England, Inc. (ISO-NE) markets for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's customers.

As a result of restructuring of the electric utility industry in Massachusetts and New Hampshire, Unitil's customers in both New Hampshire and Massachusetts have the opportunity to purchase their electric supply from competitive third-party energy suppliers. As of December 2010, 104 or 70% of Unitil's largest New Hampshire customers, representing 24% of total New Hampshire electric energy sales, and 26 or 87% of Unitil's largest Massachusetts customers, representing 36% of total Massachusetts electric energy sales, are purchasing their electric power supply in the competitive market. However, most residential and small commercial customers continue to purchase their electric supply through Unitil's distribution utilities under regulated energy rates and tariffs. The concentration of the competitive retail market on higher use customers has been a common experience throughout the New England electricity market.

Regulated Electric Power Supply

In order to provide regulated electric supply service to their customers, Unitil's distribution utilities enter into load-following wholesale electric power supply contracts with various wholesale suppliers.

Fitchburg has power supply contracts with various wholesale suppliers for the provision of Basic Service energy supply. MDPU policy dictates the pricing structure and duration of each of these contracts. Currently, all Basic Service power supply contracts for large general accounts are three months in duration and provide 100% of supply requirements. Basic Service power supply contracts for residential, small and medium general service customers are acquired every six months, are 12 months in duration and provide 50% of the supply requirements.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Unitil Energy procures Default Service supply for its large general service accounts through competitive solicitations for power contracts of three months in duration for 100%

of supply requirements. Unitil Energy procures Default Service supply for its other customers through a series of two one-year contracts and two two-year contracts, each providing 25% of the total supply requirements of the group.

The NHPUC and MDPU regularly investigate alternatives to their procurement policy, which may lead to future changes in this regulated power supply procurement structure.

Regional Electric Transmission and Power Markets

Fitchburg, Unitil Energy and Unitil Power, as well as virtually all New England electric utilities, are participants in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

In connection with the restructuring of the electric industry, Unitil Power, Unitil Energy and Fitchburg divested and sold substantially their power supply portfolios consisting of long-term power supply contracts and ownership interests in generation assets. Unitil Power, Unitil Energy and Fitchburg recover in their rates all the costs associated with this divestiture and sale and have secured regulatory approval from the FERC, NHPUC and MDPU, respectively, for the recovery of stranded costs, including long term contract buyout agreements, and other restructuring-related regulatory assets. The companies have a continuing obligation to submit regulatory filings that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Note 6: Commitments and Contingencies

Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on the Company's financial position.

A putative class action complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009, an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Ice Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2011. The Company continues to believe the suit is without merit and will defend itself vigorously.

Regulatory Matters

Overview (Unitil Energy, Fitchburg, and Northern Utilities)—Unitil's distribution utilities deliver electricity and/or natural gas to customers in the Company's service territories at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy, Fitchburg, and Northern

Utilities recover the cost of providing distribution service to their customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. As a result of the restructuring of the utility industry in New Hampshire, Massachusetts and Maine, most Unitil customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. For Northern Utilities, only business customers have the opportunity to purchase their natural gas supplies from third-party suppliers at this time. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy, Fitchburg and Northern Utilities as the providers of basic or default service energy supply. Unitil Energy, Fitchburg and Northern Utilities purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and Fitchburg divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy and Fitchburg recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDPU, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next one to four years, is $46.8 million as of December 31, 2010 including $13.3 million recorded in Current Assets as Accrued Revenue on the Company's Consolidated Balance Sheet. Unitil's distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

Fitchburg—Base Rate Case Filings—On January 14, 2011, Fitchburg filed a petition with the MDPU requesting approval of a comprehensive revenue decoupling proposals and for an increase in its electric and gas distribution rates. The Company's revenue decoupling proposal is modeled closely on proposals already approved by the Department for other gas and electric utilities operating in the Commonwealth of Massachusetts and is intended to facilitate the achievement of important public policy objectives of fostering energy efficiency, conservation and protecting the environment. The proposed rates are scheduled to change in conjunction with the implementation of revenue decoupling and are subject to the review and approval of the MDPU.

In its rate filing the Company made a request for an increase of $7.1 million in its electric distribution rates, including the recovery of deferred emergency storm restoration costs. The Company also proposed a rate-impact mitigation alternative offset, in whole, the electric distribution rate increase with a corresponding decrease in its Transition Charge. The Transition Charge is the means by which Fitchburg recovers its power supply-related stranded costs and other restructuring-related regulatory assets, discussed above. Any offsetting decrease in the Transition Charge would allow for the recovery of the restructuring related stranded costs over an extended term. The Company's filing included a request for an increase of $4.4 million in its gas distribution rates. The MDPU issued an order suspending and deferring the use of the rates until August 2, 2011, pending an investigation and analysis of the Company's filing.

Granite State Gas Transmission, Inc.—Base Rate Case Filing—On June 29, 2010, Granite State filed a base transportation rate increase of $2.3 million in annual revenue with the FERC, which is Granite State's first request for a rate change since its last general rate case in 1997. On July 30, 2010, the FERC ordered the rate increase to be effective on January 1, 2011, subject to refund and hearing and settlement procedures. On November 30, 2010, a settlement was filed on behalf of Granite State and all intervenors in the proceeding, resolving all issues in the docket. The settlement provides for an increase of approximately $1.7 million in annual revenue, based on new gas transportation rates to be effective January 1, 2011. The settlement was approved by the FERC on January 31, 2011.

Unitil Energy Rate Case Filing—On April 15, 2010, Unitil Energy filed a proposed base rate increase of $10.1 million, an increase of 6.5 percent above present rates. In addition, Unitil Energy's filing also included a proposed long-term rate plan establishing future rate step adjustments for utility plant investments and enhanced reliability and vegetation management program expenditures. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy of $5.2 million (annual) effective July 1, 2010 which is being collected by a uniform per kilowatt-hour (kWh) surcharge of $0.00438 on each of Unitil Energy's current rate schedules. Once permanent rates are approved by the NHPUC, they

will be reconciled to the date temporary rates were ordered, July 1, 2010. The Company is currently engaged in settlement proceedings regarding the permanent rate level and a long-term rate plan. A hearing in this matter is scheduled for early February 2011.

Major Wind Storm—On February 25, 2010, a significant wind storm struck portions of the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including approximately 85% of the Unitil Energy's customers. The Company spent approximately $7.4 million for the repair and replacement of electric distribution systems damaged during the storm, including $1.5 million related to capital construction and $5.9 million which has been deferred as a regulatory asset. Unitil Energy, in its base rate case filing discussed above, has requested recovery in rates for the costs associated with the emergency repair of its electric distribution system for damage caused by this storm.

Major Ice Storm—On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region. The Company spent approximately $24.0 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.6 million related to capital construction and $15.4 million which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. If the Company is unable to recover a significant amount of these deferred storm costs, or if the Company's recovery of these costs is significantly delayed, then the Company's financial condition or results of operations could be adversely affected.

On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. On September 24, 2010, the NHPUC issued its final order in this matter and closed its investigation, accepting the NHPUC Staff's report finding that Unitil Energy had acted reasonably.

On November 9, 2009, the NHPUC granted Unitil Energy's petition to defer and record as a regulatory asset costs associated with electric distribution system damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's pending base rate case. The order clarified that the issues of the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are to be reviewed in the rate case. As of December 31, 2010, Unitil Energy has deferred approximately $2.2 million associated with the repair of its electric distribution system for future recovery in rates.

On December 30, 2009, the MDPU approved Fitchburg's petition to defer and record as a regulatory asset costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. The order of approval made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and confirmed that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. As of December 31, 2010, Fitchburg has deferred approximately $13.2 million associated with the repair of its electric distribution system for future recovery in rates.

The MDPU conducted an investigation of Fitchburg's preparation for, and response to, the December 2008 Ice Storm during the first half of 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service, and ordered several remedial actions. First, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices. The management audit, which is being performed by Jacobs Consultancy, Inc., began in the fourth quarter of 2010. Second, the MDPU directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. All of these operational and capital improvements have either been completed or are being implemented, and remain subject to MDPU review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

Fitchburg—Electric Operations—On November 24, 2010, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery continues through a Transition Charge Surcharge of $0.00400 per kWh. Changes to the Pension/PBOP Adjustment, Residential Assistance Adjustment Factor, and Net Metering Recovery Surcharge were proposed in other proceedings. The rates were approved effective January 1, 2011, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order on Fitchburg's 2009 Annual Reconciliation Filing also remains pending.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting regulations concerning the items required by House Bill 4329. On July 30, 2010, the MDPU approved Fitchburg's electric and gas Emergency Response Plans.

Fitchburg—Gas Operations—On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement order to the Massachusetts SJC. Fitchburg believes that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. The Company filed its Initial brief in this matter on January 10, 2011. This appeal remains pending before the Massachusetts SJC.

Fitchburg—Other—On February 11, 2009, the Massachusetts SJC issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The Massachusetts SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Massachusetts SJC, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts singed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three-year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, special tariffs to allow the net metering of customer-owned renewable generation, and terms and conditions for purchasing supplier receivables. Three year energy efficiency investment plans, plans to establish smart grid pilot programs, and net metering tariffs have been approved by the MDPU. Proposals to purchase long-term contracts for renewable energy and terms and conditions for purchasing supplier receivables are under review in a separately designated docket.

On March 1, 2010, Fitchburg submitted its annual filing to the MDPU of the 2009 Service Quality Reports for both its gas and electric divisions. On October 20, 2010, the MDPU issued its order with respect to Fitchburg's gas division's Report and noted that Fitchburg met or exceeded its established benchmarks in all Service Quality measures, that Fitchburg's performance was consistent with the MDPU's Service Quality Guidelines and Fitchburg's Service Quality plan. An order on Fitchburg's electric division's Service Quality plan has not yet been issued and the matter remains pending.

Unitil Energy—Other—In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources (DER). An order approving a settlement agreement for a time-of-use pilot program was issued on February 26, 2010. On June 11, 2010, the NHPUC issued an order on the remaining two proposed projects and cost recovery. The NHPUC denied one of the two projects, citing that the costs outweighed the benefits but found the other project to be in the public interest. On November 1, 2010 Unitil Energy filed adjustments to base distribution rates to collect actual costs associated with authorized DER projects. This matter remains pending.

On June 17, 2010, Unitil Energy made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2010, including reconciliation of prior year costs and revenues. On July 30, 2010, the NHPUC approved the rate filing and reconciliation.

Northern Utilities—On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation (NOPVs) of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's consolidated balance sheet at December 31, 2010 was $0.7 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in portions of Northern Utilities' Maine service areas. In an order issued on July 30, 2010, the MPUC approved a Settlement Agreement resolving this matter, filed on behalf of Northern Utilities, the Maine Office of the Public Advocate, and several state legislator intervenors, which was filed with the MPUC on July 6, 2010. Under the Agreement, Northern Utilities will proceed with a comprehensive upgrade and replacement program (the Program), which will provide for the systematic replacement of cast iron, wrought iron and bare steel pipe in Northern Utilities' natural gas distribution system in Portland and Westbrook, Maine and the conversion of the system to intermediate pressure. The Agreement establishes the objective of completing the Program by the end of the 2024 construction season. Under the Agreement, the parties agreed to support a cost recovery mechanism that will provide for the timely recovery of prudently-incurred costs of the Program. The features of this cost recovery mechanism will be finalized during Northern Utilities' next base rate case proceeding, which is anticipated to be filed in early 2011.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Fitchburg's Manufactured Gas Plant Site—Fitchburg continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. Fitchburg has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection, which allows Fitchburg to work towards temporary closure of the site. A status of temporary closure requires Fitchburg to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Fitchburg recovers the environmental response costs incurred at this former MGP site in gas rates pursuant to terms of a cost recovery agreement approved by the MDPU. Pursuant to this agreement, Fitchburg is authorized to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition, Fitchburg has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. In January 2011, Fitchburg settled with the remaining insurance carriers for approximately $2.0 million and expects to receive these payments in the first quarter of 2011. Any recovery that Fitchburg receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are shared equally between Fitchburg and its gas customers.

Fitchburg is in the process of developing long-range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at December 31, 2010 and 2009 in Environmental Obligations are accrued liabilities totaling $12.0 million and $12.0 million, respectively, related to estimated future clean up costs for permanent remediation of the Sawyer Passway site. A corresponding Regulatory Asset was recorded to reflect that the recovery of this environmental remediation cost is probable through the regulatory process. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

Northern Utilities Manufactured Gas Plant Sites—Northern Utilities has an extensive program to identify, investigate and remediate former MGP sites that were operated from the mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. This program has also documented the presence of MGP sites in Lewiston and Portland, Maine and a former MGP disposal site in Scarborough, Maine. Northern Utilities has worked with the environmental regulatory agencies in both New Hampshire and Maine to address environmental concerns with these sites.

Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Somersworth, Portsmouth, and Scarborough sites. The sites in Lewiston and Portland have been investigated and remedial activities are currently underway. Future operation, maintenance and remedial costs have been accrued, although there will be uncertainty regarding future costs until all remedial activities are completed.

The NHPUC and MPUC have approved the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC approved the recovery of MGP environmental costs over a seven-year amortization period. For Northern Utilities' Maine division, the MPUC authorized the recovery of environmental remediation costs over a rolling five-year amortization schedule.

Include in the Company's Consolidated Balance Sheets at December 31, 2010 and 2009 are current and non-current accrued liabilities totaling $2.6 million and $2.5 million, respectively, associated with Northern Utilities environmental remediation obligations for these former MGP sites. A corresponding Regulatory Asset was recorded to reflect that the recovery of these environmental remediation cost is probable through the regulatory process.

The Company's ultimate liability for future environmental remediation costs, including MGP site costs, may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

The following table shows the balances and activity in the Company's liability for Environmental Obligations for 2010.

ENVIRONMENTAL OBLIGATIONS

(Millions)	December 31, 2010	2009
Total Environmental Obligations—Balance at Beginning of Period	**$14.5**	$12.7
Changes in Estimates	**0.2**	1.8
Liabilities Assumed	**—**	—
Payments/Reductions	**0.1**	—
Total Environmental Obligations—Balance at End of Period	**14.6**	14.5
Less: Current Portion [1]	**0.1**	0.2
Environmental Obligations—noncurrent—Balance at End of Period	**$14.5**	$14.3

(1) Reflects amounts included in Other Current Liabilities on the Company's Consolidated Balance Sheets.

Note 7: Bad Debts

Unitil's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. In 2010, 2009 and 2008, the Company recorded provisions for the energy commodity portion of bad debts of $1.4 million, $1.9 million and $2.1 million, respectively. These provisions were recognized in Purchased Electricity and Purchased Gas expense as the associated electric and gas utility revenues were billed. Purchased Electricity and Purchased Gas costs are recovered from customers through periodic rate reconciling mechanisms.

The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2008—2010 ($ millions):

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	(a) Other	Provision	Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2010						
Electric	**$1.7**	**$ —**	**$2.0**	**$0.2**	**$2.1**	**$1.8**
Gas	**0.7**	**—**	**2.5**	**0.4**	**2.9**	**0.7**
Other	**0.1**	**—**	**—**	**—**	**—**	**0.1**
	$2.5	**$ —**	**$4.5**	**$0.6**	**$5.0**	**$2.6**
Year Ended December 31, 2009						
Electric	$1.1	$ —	$2.3	$0.2	$1.9	$1.7
Gas	1.8	0.5	1.4	0.3	3.3	0.7
Other	0.1	—	—	—	—	0.1
	$3.0	$0.5	$3.7	$0.5	$5.2	$2.5
Year Ended December 31, 2008						
Electric	$1.0	$ —	$2.2	$0.2	$2.3	$1.1
Gas	0.2	1.4	1.4	0.2	1.4	1.8
Other	0.1	—	—	—	—	0.1
	$1.3	$1.4	$3.6	$0.4	$3.7	$3.0

(a) Includes Allowance for Doubtful Accounts of Northern Utilities and Granite State, which were acquired on December 1, 2008.

Note 8: Income Taxes

Provisions for Federal and State Income Taxes reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2010, 2009 and 2008 are shown in the table below:

	($000's)		
	2010	**2009**	**2008**
Current Federal Tax Provision (Benefit)			
Current Benefit of Operating Loss Carrybacks	**$ (6,026)**	$(3,226)	$(2,914)
Total Current Federal Tax Provision (Benefit)	**(6,026)**	(3,226)	(2,914)
Deferred Federal Tax Provision (Benefit)			
Utility Plant Differences	**11,821**	8,716	5,159
Net Operating Loss Carryforwards	**(5,520)**	—	—
Regulatory Assets and Liabilities	**3,338**	(1,308)	1,534
Other, net	**(480)**	(120)	121
Total Deferred Federal Tax Provision (Benefit)	**9,159**	7,288	6,814
Total Federal Tax Provision	**3,133**	4,062	3,900
State			
Current	**28**	1,578	123
Deferred	**1,303**	(218)	592
Total State Tax Provision	**1,331**	1,360	715
Total Provision for Federal and State Income Taxes	**$ 4,464**	$ 5,422	$ 4,615

The differences between the Company's provisions for Income Taxes, including the provision for Business Enterprise taxes, and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2010	**2009**	**2008**
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**6**	6	5
Utility Plant Differences	**(7)**	(3)	(6)
Other, Net	**(1)**	(1)	(1)
Effective Income Tax Rate	**32%**	36%	32%

Temporary differences, including the effect of deferred tax accounting on utility plant differences and accrued revenue regulatory assets, which gave rise to deferred tax assets and liabilities, are shown below:

Deferred Income Taxes (000's)	**2010**	**2009**
Depreciation and Utility Plant	**$ 44,608**	$ 30,318
Net Operating Loss Carryforwards	**(8,567)**	—
AMT Tax Credit Carryforwards	**(1,366)**	—
Regulatory Assets/Liabilities & Mechanisms	**33,421**	29,094
Retirement Benefit Obligations	**(25,155)**	(22,537)
Other, net	**883**	2,896
Total Deferred Income Tax Liabilities	**$ 43,824**	$ 39,771

The Company is subject to Federal and State income taxes as well as various other business taxes. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining the current and deferred tax assets and liabilities. The Company's current and deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. Periodically, the Company assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Concurrent with filing its 2009 Federal income tax return in September of 2010, the Company changed its method of tax accounting for certain construction-related costs previously capitalized as depreciable assets, to account for those expenditures as repairs expense deductions under Sections 162 and 263(a) of the Internal Revenue Code (IRC). In applying the new tax accounting method, certain costs which were previously capitalized and recognized as depreciation deductions over various useful lives for tax accounting purposes are now to be deducted in the year incurred.

The Company applied the tax accounting method change retroactively for additional deductions of \$23.9 million in its Federal Income Tax return filing for the year ended December 31, 2009 which resulted in a 2009 net operating loss (NOL) of \$26.5 million. As a result, the Company recognized NOL carrybacks against its Federal Income Tax returns for the years ended December 31, 2004, 2005, and 2007 in the amounts of \$1.1 million, \$12.8 million, and \$9.6 million, respectively. The carryback of the 2009 NOL resulted in current tax refunds of \$7.5 million and remaining unused NOL and Alternative Minimum Tax (AMT) credit carryforwards of \$3.0 million and \$1.4 million respectively.

According to IRC rules, NOL refunds in excess of \$2.0 million fall under the jurisdiction of the Joint Committee of Congress (Joint Committee) and are subject to review by the Internal Revenue Service (IRS) and attorneys of the Joint Committee. The Company expects to receive notice of examination for the 2009 Federal Income Tax return filings under the Joint Committee rules. The Company remains subject to examination by Federal, Maine, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2009; December 31, 2008; and December 31, 2007.

In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized NOL carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of \$5.0 million and \$6.7 million, respectively. These NOL carrybacks resulted in a refund to the Company of \$4.0 million which was received in November 2009. As a result, on December 30, 2009, the Company received notice that its Federal Income Tax return filings for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 were under examination by the IRS. The IRS has performed all fieldwork procedures and the company and the IRS have entered into a settlement, pending approval of the Joint Committee, for certain timing items deducted in previous years to be deducted in the Federal Income Tax return filings for year ended December 31, 2009. As a result of the settlement, in November 2010 the Company paid \$0.2 million and \$1.5 million for tax years 2006 and 2007, respectively. The amount paid included interest of \$0.1 million and \$0.1 million for tax years 2006 and 2007, respectively which is recorded in Interest Expense, Net for 2010 in the Consolidated Statements of Earnings.

In total at December 31, 2010, the Company had generated NOL carryforwards for income tax purposes of \$8.5 million that will expire in 2011 through 2030, if not utilized. In addition, at December 31, 2010, the Company had \$1.4 million of AMT credit carryforwards to offset future AMT indefinitely.

The Company evaluated its tax positions at December 31, 2010 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by the FASB Codification is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months.

Note 9: Segment Information

Unitil reports four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capitol regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern Maine to the Lewiston-Auburn area and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine.

Granite State is an interstate natural gas transmission pipeline company, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transmission services provided to Northern Utilities and, to a lesser extent, third-party marketers.

Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies. Unitil Resources and Usource are included in the Non-Regulated column below.

Unitil Realty, Unitil Service and the holding company are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries' use.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes and preferred stock dividends. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on cost allocation factors included in rate applications approved by the NHPUC, MDPU, and MPUC. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2010, 2009 and 2008 (Millions):

Year Ended December 31, 2010	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$203.7**	**$150.1**	**$ —**	**$4.6**	**$358.4**
Interest Income	**3.2**	**0.5**	**0.2**	**0.1**	**4.0**
Interest Expense	**9.6**	**10.5**	**2.0**	**—**	**22.1**
Depreciation & Amortization Expense	**13.9**	**14.2**	**0.8**	**—**	**28.9**
Income Tax Expense (Benefit)	**3.7**	**(0.7)**	**0.5**	**1.0**	**4.5**
Segment Profit (Loss)	**8.0**	**1.4**	**(1.4)**	**1.5**	**9.5**
Segment Assets	**377.7**	**370.8**	**5.7**	**5.4**	**759.6**
Capital Expenditures	**19.8**	**27.4**	**2.4**	**—**	**49.6**
Year Ended December 31, 2009					
Revenues	$209.9	$152.8	$ —	$4.3	$367.0
Interest Income	3.6	0.5	0.7	—	4.8
Interest Expense	9.1	9.7	1.8	—	20.6
Depreciation & Amortization Expense	14.0	12.8	0.6	—	27.4
Income Tax Expense (Benefit)	2.4	1.9	0.1	1.0	5.4
Segment Profit (Loss)	4.9	3.3	0.1	1.6	9.9
Segment Assets	365.6	349.7	7.3	2.6	725.2
Capital Expenditures	27.7	30.0	1.0	—	58.7
Year Ended December 31, 2008					
Revenues	$227.5	$ 56.9	$ —	$3.8	$288.2
Interest Income	2.2	0.1	0.3	—	2.6
Interest Expense	8.7	2.3	2.1	—	13.1
Depreciation & Amortization Expense	13.1	5.2	0.8	—	19.1
Income Tax Expense (Benefit)	1.9	2.6	(0.1)	0.2	4.6
Segment Profit (Loss)	5.2	4.3	(0.2)	0.3	9.6
Segment Assets	372.2	350.9	9.1	1.0	733.2
Capital Expenditures	19.7	7.6	1.0	—	28.3

Note 10: Retirement Benefit Plans

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan)—The Pension Plan is a defined benefit pension plan. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service. In September 2009, the Company amended the Pension Plan as follows:
  - The Pension Plan was closed to non-union employees hired on or after January 1, 2010.

- All non-union employees hired before January 1, 2010 had a choice of either:
    - Remaining in the Pension Plan with the existing set of benefits, or
    - Electing to move to Unitil Corporation's enhanced Tax Deferred Savings and Investment Plan. Non-union employees who elected this option received a frozen benefit from the existing Pension Plan for all of the benefits that they had accrued to December 31, 2009. This frozen benefit will not grow with future salary increases or future service. Non-union employees who elected this option will receive an enhanced employer matching contribution as well as a Company contribution in the Unitil Corporation Tax Deferred Savings and Investment Plan.
    - Union employees were not affected by this amendment.

In September 2010, the Company amended the Pension Plan as follows:

- The Pension Plan was closed to United Steelworker Local 12012-6 employees hired on or after January 1, 2011.
- All United Steelworker Local 12012-6 employees hired before January 1, 2011 had a choice of either:
    - Remaining in the Pension Plan with the existing set of benefits, or
    - Electing to move to Unitil Corporation's enhanced Tax Deferred Savings and Investment Plan. The United Steelworker Local 12012-6 employees who elected this option received a frozen benefit from the existing Pension Plan for all of the benefits that they had accrued to December 31, 2010. This frozen benefit will not grow with future salary increases or future service. The employees who elected this option will receive an enhanced employer matching contribution as well as a Company contribution in the Unitil Corporation Tax Deferred Savings and Investment Plan.
    - All other union employees were not affected by this amendment.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan)—The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan. In 2009, the Company made the following changes to the PBOP Plan.

<u>Changes to Utility Workers Union of America Local 341 Benefits</u>

A new Collective Bargaining Agreement ("Agreement") was entered into between Northern Utilities, Inc., Granite State Gas Transmission, Inc. and Utility Workers Union of America Local 341 ("UWUA") for the period April 1, 2009 through March 31, 2012. Included in the Agreement were changes to retiree medical benefits under the Plan. These changes are as follows:

- Retirees under sixty-five (65) years and their dependents will be covered by the medical benefits provided by the PBOP Plan. Early retirees will be responsible for contributing 20% of the premium for medical insurance for themselves and their dependents until age sixty-five (65).
- Retirees over sixty-five (65) years will be covered by a Supplement to Medicare Plan and will be responsible for a 20% premium cost sharing.
- For all employees hired on or after April 1, 2009, no post-65 retiree medical coverage will be provided.
- The Company is to determine post-65 drug coverage to be offered to all future retirees eligible for retiree medical.

These above-referenced retiree medical provisions were effective January 1, 2010.

Changes to United Steelworker Local 12012-6 Benefits

A new Collective Bargaining Agreement ("Agreement") was entered into between Northern Utilities, Inc. and United Steelworker Local 12012-6 ("USW") for the period June 6, 2010 through June 5, 2014. Included in the Agreement were changes to retiree medical benefits under the Plan. These changes are as follows:

- Retirees under sixty-five (65) years and their dependents will be covered by the medical benefits provided by the PBOP Plan. Early retirees will be responsible for contributing 20% of the premium for medical insurance for themselves and their dependents until age sixty-five (65).
- Retirees over sixty-five (65) years will be covered by a Supplement to Medicare Plan and will be responsible for a 20% premium cost sharing.
- For all employees hired on or after June 6, 2010, no post-65 retiree medical coverage will be provided.

These above-referenced retiree medical provisions were effective June 6, 2010.

Changes to Non-Union Employee Benefits

In September 2009, the Company announced the following PBOP Plan changes, effective January 1, 2010, for non-union employees:

- Employees who retire on or after January 1, 2010 will pay 20% of the cost of their retiree medical benefits.
- Employees who retire on or after January 1, 2010 will not receive any cash payments towards their Medicare premiums.
- Employees who are hired on or after January 1, 2010 will only be provided with company subsidized medical insurance until they reach age 65 and will not receive a Medicare supplement plan after age 65.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP)—The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

Effective with the acquisitions of Northern Utilities and Granite State, the Company assumed the assets and obligations of the Northern Utilities and Granite State pension plans with respect to active union employees. All other active employees of Northern Utilities and Granite State effectively became members of the Company's Pension Plan as of the acquisitions closing date.

Certain employees of Northern Utilities qualified for participation in the Company's PBOP Plan effective with the acquisition closing date.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan costs for years ended December 31:	2010	2009	2008
Discount Rate [1]	**5.75%**	6.25%	6.00%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.50%**	8.00%	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017	2017
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 728**	$ 735	$ 675
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$ (565)**	$ (576)	$ (531)

(1) As a result of the changes to the PBOP Plan in September 2009 discussed above, the Company was required to update the discount rate used in determining the PBOP Plan costs for the remainder of 2009. Based on the market rates for long-term bonds at that time, the Company assumed a discount rate of 5.50% for the PBOP Plan from September through December of 2009.

Used to Determine Benefit Obligations at December 31:

Discount Rate	**5.35%**	5.75%	6.25%
Rate of Compensation Increase	**3.50%**	3.50%	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.00%**	7.50%	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2017	2017
Effect of 1% Increase in Health Care Cost Trend Rate (000's)	**$ 7,530**	$ 5,887	$ 6,084
Effect of 1% Decrease in Health Care Cost Trend Rate (000's)	**$(5,997)**	$(4,704)	$(4,890)

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2010, 2009 and 2008, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000, $300,000 and $200,000, respectively, in the Net Periodic Benefit Cost (NPBC). The Rate of Compensation Increase assumption used for 2010, 2009 and 2008 was 3.50%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan			PBOP Plan			SERP		
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Service Cost	**$ 2,608**	$ 2,282	$ 1,979	**$ 1,466**	$ 1,417	$ 1,447	**$285**	$217	$150
Interest Cost	**4,457**	4,294	3,800	**2,016**	2,269	2,212	**227**	181	126
Expected Return on Plan Assets	**(4,181)**	(4,432)	(4,390)	**(599)**	(440)	(325)	**—**	—	—
Prior Service Cost Amortization	**253**	264	119	**1,579**	1,634	1,390	**2**	(2)	(1)
Transition Obligation Amortization	**—**	—	—	**21**	21	21	**—**	—	—
Curtailment Loss	**41**	32	—	**—**	—	—	**—**	—	—
Actuarial Loss Amortization	**2,406**	1,598	1,274	**—**	—	—	**133**	70	24
Sub-total	**5,584**	4,038	2,782	**4,483**	4,901	4,745	**647**	466	299
Amounts Capitalized and Deferred	**(2,240)**	(1,409)	(893)	**(1,183)**	(1,642)	(1,872)	**—**	—	—
NPBC Recognized	**$ 3,344**	$ 2,629	$ 1,889	**$ 3,300**	$ 3,259	$ 2,873	**$647**	$466	$299

The estimated amortizations related to Actuarial Loss and Prior Service Cost included in the Company's Retirement plan costs over the next fiscal year is $3.4 million, $1.7 million and $0.1 million for the Pension, PBOP and SERP plans, respectively.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense for the years 2010, 2009 and 2008 before capitalization and deferral was $5.6 million, $4.0 million and $2.8 million, respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense for the years 2010, 2009 and 2008 would have been $6.2 million, $6.3 million and $2.9 million respectively.

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan		PBOP Plan		SERP	
Change in Plan Assets:	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Plan Assets at Beginning of Year	**$ 47,082**	$ 39,124	**$ 6,306**	$ 4,361	**$ —**	$ —
Actual Return on Plan Assets	**5,901**	8,017	**922**	874	**—**	—
Employer Contributions	**4,302**	4,227	**3,482**	2,800	**53**	53
Participant Contributions	**—**	—	**—**	2	**—**	—
Acquired Plan Assets	**—**	(544)	**—**	—	**—**	—
Benefits Paid	**(3,185)**	(3,742)	**(1,848)**	(1,731)	**(53)**	(53)
Plan Assets at End of Year	**$ 54,100**	$ 47,082	**$ 8,862**	$ 6,306	**$ —**	$ —
Change in PBO:						
PBO at Beginning of Year	**$ 79,288**	$ 70,386	**$ 35,694**	$ 37,655	**$ 3,979**	$ 2,930
Service Cost	**2,608**	2,282	**1,466**	1,417	**285**	217
Interest Cost	**4,457**	4,294	**2,016**	2,269	**227**	181
Participant Contributions	**—**	—	**—**	2	**—**	—
Plan Amendments	**—**	—	**1,683**	(2,382)	**138**	—
Estimated Acquired Obligations	**—**	—	**—**	—	**—**	—
Curtailment Gain	**(1)**	(599)	**—**	—	**—**	—
Benefits Paid	**(3,185)**	(3,742)	**(1,848)**	(1,731)	**(53)**	(53)
Actuarial (Gain) or Loss	**6,226**	6,667	**4,333**	(1,536)	**(313)**	704
PBO at End of Year	**$ 89,393**	$ 79,288	**$ 43,344**	$ 35,694	**$ 4,263**	$ 3,979
Funded Status: Assets vs PBO	**$(35,293)**	$(32,206)	**$(34,482)**	$(29,388)	**$(4,263)**	$(3,979)

The Company has recorded on its consolidated balance sheets as a liability the underfunded status of their retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets of $47.1 million and $43.7 million at December 31, 2010 and 2009, respectively, to recognize the future collection of these plan obligations in electric and gas rates.

The Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $78.4 million and $69.0 million as of December 31, 2010 and 2009, respectively. The ABO for the SERP was $0.5 million and $0.5 million as of December 31, 2010 and 2009, respectively. For the PBOP Plan, the ABO and PBO are the same.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92% – 100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in

the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 – 2010 plan years. The Company's Pension Plan was 80% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2010 which resulted in a shortfall of $10.2 million. This shortfall is being amortized over seven years with annual payments of $1.7 million, beginning in 2010. The $1.7 million payment for 2010 is included in the Employer Contributions amount shown in the table below. On June 25, 2010, the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 (Relief Act) was signed into law. The pension relief portion of the Relief Act provides two alternative shortfall amortization periods to the seven year amortization period required under the PPA. The Company has evaluated the two alternative shortfall amortization periods under the Relief Act and made the decision to continue with the seven year amortization period. The Company, along with its subsidiaries, expects to continue to make contributions to its Pension Plan in 2011 and future years at minimum required and discretionary funding levels consistent with the amounts recovered in the distribution utilities' rates for these Pension Plan costs.

The following table represents employer contributions and benefit payments ($000's). There were no participant contributions.

	Pension Plan			PBOP Plan			SERP		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Employer Contributions	**$4,302**	$4,227	$2,800	**$3,482**	$2,800	$2,700	**$53**	$53	$59
Benefit Payments	**$3,185**	$3,742	$2,796	**$1,848**	$1,731	$1,699	**$53**	$53	$59

The following table represents estimated future benefit payments ($000's).

	Estimated Future Benefit Payments		
	Pension	**PBOP**	**SERP**
2011	$ 3,740	$ 1,512	$ 52
2012	3,958	1,613	51
2013	4,144	1,710	320
2014	4,365	1,824	318
2015	4,525	1,939	317
2016 - 2020	$26,922	$11,327	$1,555

The Expected Long-Term Rate of Return on Pension Plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on Pension Plan assets is based on target investment allocation of 57% in common stock equities and 43% in fixed income securities. The Company's Expected Long-Term Rate of Return on PBOP Plan assets is based on target investment allocation of 55% in common stock equities and 45% in fixed income securities. The actual investment allocations are shown in the tables below.

Pension Plan	**Target Allocation 2011**	**Actual Allocation at December 31,**		
		2010	**2009**	**2008**
Equity Securities	57%	**58%**	59%	54%
Debt Securities	43%	**42%**	40%	35%
Other	0%	**0%**	1%	11%
Total		**100%**	100%	100%

PBOP Plan	**Target Allocation 2011**	**Actual Allocation at December 31,**		
		2010	**2009**	**2008**
Equity Securities	55%	**56%**	56%	56%
Debt Securities	45%	**44%**	44%	44%
Total		**100%**	100%	100%

(1) Represents investments in Money Market Funds.

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.50% for 2010. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 5 – 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The FASB Codification defines fair value, and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under the FASB Codification are described below:

Level 1 – Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Valuations based on quoted prices in markets that are not active or for which all significant inputs are observable, either directly or indirectly.

Level 3 – Prices or valuations that require inputs that are both significant to the fair value measurement and unobservable.

To the extent that valuation is based on models or inputs that are less observable or unobservable in the market, the determination of fair value requires more judgment. Accordingly, the degree of judgment exercised by the Company in determining fair value is greatest for instruments categorized in Level 3. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Fair value is a market-based measure considered from the perspective of a market participant rather than an entity-specific measure. Therefore, even when market assumptions are not readily available, the Company's own assumptions are set to reflect those that market participants would use in pricing the asset or liability at the measurement date. The Company uses prices and inputs that are current as of the measurement date, including during periods of market dislocation. In periods of market dislocation, the observability of prices and inputs may be reduced for many instruments. This condition could cause an instrument to be reclassified from Level 1 to Level 2 or from Level 2 to Level 3.

Valuation Techniques

There have been no changes in the valuation techniques used during the current period.

Assets measured at fair value on a recurring basis for the Pension Plan as of December 31, 2010 and 2009 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	**Balance as of December 31, 2010**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Pension Plan Assets:				
Mutual Funds:				
Balanced Funds	$31,625	$31,625	$—	$—
Fixed Income Funds	22,475	22,475		
Total Assets	$54,100	$54,100	$—	$—

Description	Fair Value Measurements at Reporting Date Using			
	Balance as of December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension Plan Assets:				
Mutual Funds:				
Balanced Funds	$27,706	$27,706	$—	$—
Fixed Income Funds	18,961	18,961	—	—
Total Mutual Funds	$46,667	$46,667	—	—
Cash Equivalents	415	415	—	—
Total Assets	$47,082	$47,082	$—	$—

Assets measured at fair value on a recurring basis for the PBOP Plan as of December 31, 2010 and 2009 are as follows ($000’s):

Description	Fair Value Measurements at Reporting Date Using			
	Balance as of December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$3,936	$3,936	$—	$—
Index Funds	3,580	3,580		
Balanced Funds	1,346	1,346		
Total Assets	$8,862	$8,862	$—	$—

Description	Fair Value Measurements at Reporting Date Using			
	Balance as of December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$2,776	$2,776	$—	$—
Index Funds	2,582	2,582		
Balanced Funds	948	948		
Total Assets	$6,306	$6,306	$—	$—

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company’s employees. Participants may elect to defer current compensation by contributing to the plan. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company common stock fund.

In September 2009, the Company amended the Plan as follows:

For current non-union employees who elect to stay with the Company’s existing Pension Plan, there will be no changes in the 401(k) Plan. For those employees, the Company will continue to match contributions, with a maximum matching contribution of 3% of current compensation and those participants will be 100% vested in these company matching contributions once they have completed three years of service.

For non-union employees who are hired on or after January 1, 2010, and for non-union employees who elect to move from the Company's existing Pension Plan and accept a frozen pension benefit, the Company will provide the following enhancements to the 401(k) Plan:

- The Company will contribute 4% of base pay each year, regardless of whether or not the non-union employee elects to contribute to the 401(k) Plan.
- The Company will increase the matching contributions from 3% of base pay to 6% of base pay. This will be a 100% match of the first 6% of the non-union employee's contributions.
- All Company contributions will be 100% vested at all times.
- New non-union employees will be automatically enrolled in the 401(k) Plan following the completion of 1,000 hours of service, with the automatic contribution rate of 3%. This contribution rate will automatically increase by 1% on January 1 of each year until the non-union employee's contribution is 10% of pay. Non-union employees may elect to opt-out of the automatic enrollment and/or automatic increase features of the enhanced 401(k) Plan.

The Company's contributions to the 401(k) Plan were $980,000, $671,000 and $542,000 for the years ended December 31, 2010, 2009, and 2008, respectively.

Note 11: Quarterly Financial Information (unaudited; Millions, except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding and the impact of additional common share issuances. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Total Operating Revenues	**$113.0**	$135.6	**$ 71.4**	$ 71.5	**$ 76.1**	$ 70.4	**$ 97.9**	$ 89.5
Operating Income	**$ 10.9**	$ 13.9	**$ 2.7**	$ 4.2	**$ 4.6**	$ 3.4	**$ 9.8**	$ 4.6
Net Income (Loss) Applicable to Common	**$ 6.5**	$ 9.1	**$ (2.1)**	$ 0.2	**$ (0.1)**	$ (0.6)	**$ 5.2**	$ 1.2
	Per Share Data:							
Earnings Per Common Share	**$ 0.61**	$ 1.14	**$ (0.19)**	$ 0.03	**$ (0.01)**	$ (0.06)	**$ 0.48**	$ 0.11
Dividends Paid Per Common Share	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345	**$0.345**	$0.345

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

On July 21, 2010, the Company was notified that effective July 20, 2010, McGladrey & Pullen, LLP (McGladrey) acquired certain assets of Caturano and Company, Inc. (formerly Caturano and Company, P.C.), the Company's independent registered public accounting firm (Caturano) and substantially all of the officers and employees of Caturano joined McGladrey. As a result, Caturano resigned as the independent registered public accounting firm for the Company and McGladrey was appointed by the Audit Committee of the Company's Board of Directors as the Company's new independent registered public accounting firm on September 22, 2010.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, conducted an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of December 31, 2010. Based on this evaluation, the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded as of December 31, 2010 that the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f).

Under the supervision and with the participation of management, including the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, Unitil management has evaluated the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, based upon criteria established in the "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, Unitil management concluded that Unitil's internal control over financial reporting was effective as of December 31, 2010.

McGladrey and Pullen, LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2010, as stated in their report which appears in Part II, Item 8 herein.

Changes in Internal Control over Financial Reporting

There have been no changes in Unitil's internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fiscal quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, Unitil's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers of the Registrant and Corporate Governance

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K and in the “Proposal I: Election of Directors” section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011. Information regarding the Company’s Audit Committee is set forth in the “Corporate Governance and Policies of the Board” and “Committees of the Board” sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011. Information regarding the Company’s Code of Ethics is set forth in the “Corporate Governance and Policies of the Board” section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

Item 11. Executive Compensation

Information required by this Item is set forth in the “Compensation Discussion and Analysis” and “Compensation of Named Executive Officers” sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this Item is set forth in the “Beneficial Ownership” and “As to the Election of Directors” sections of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011, as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this Item is set forth in the “Transactions with Related Persons” section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the “Principal Accountant Fees and Services” section of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2011.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Reports of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2010 and 2009
- Consolidated Statements of Earnings for the years ended December 31, 2010, 2009, and 2008
- Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009, and 2008
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2010, 2009, and 2008
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	Articles of Amendment to the Articles of Incorporation Filed on September 23, 2008.	Exhibit 3.3 to Form S-3/A dated November 25, 2008
3.4	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.5	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.6	Articles of Exchange of CECo, E&H, and the Company—Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.7	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (Fitchburg) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.8	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002

Exhibit Number	Description of Exhibit	Reference*
4.2	Fitchburg Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.3	Fitchburg Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.4	Fitchburg Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.5	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.6	Fitchburg Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
4.7	Fitchburg Note Agreement dated December 21, 2005 for the 5.90% Notes due December 15, 2030.	**
4.8	Thirteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of September 26, 2006.	**
4.9	Unitil Corporation Note Purchase Agreement, dated as of May 2, 2007, for the 6.33% Senior Notes due May 1, 2022.	**
4.10	Northern Utilities Note Purchase Agreement, dated as of December 3, 2008, for the 6.95% Senior Notes, Series A due December 3, 2018 and the 7.72% Senior Notes, Series B due December 3, 2038.	Exhibit 4.1 to Form 8-K dated December 3, 2008
4.11	Granite State Note Purchase Agreement, dated as of December 15, 2008, for the 7.15% Senior Notes due December 15, 2018.	Exhibit 99.1 to Form 8-K dated December 15, 2008
4.12	Northern Utilities Note Purchase Agreement, dated as of March 2, 2010, for the 5.29% Senior Notes, due March 2, 2020.	Exhibit 4.1 to Form 8-K dated March 2, 2010
4.13	Fourteenth Supplemental Indenture of Unitil Energy Systems, Inc., dated as of March 2, 2010.	Exhibit 4.4 to Form 8-K dated March 2, 2010
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 8-K dated June 19, 2008
10.5***	Amended and Restated Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.3 to Form 8-K dated June 19, 2008
10.6***	Amended and Restated Unitil Corporation Supplemental Executive Retirement Plan effective as of December 31, 2007.	Exhibit 10.4 to Form 8-K dated June 19, 2008

Exhibit Number	Description of Exhibit	Reference*
10.7***	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.8***	Amended and Restated Unitil Corporation Management Incentive Plan effective as of June 19, 2008 as further amended on December 1, 2008.	Exhibit 10.8 to Form 10-K for 2008
10.9	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.10***	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.11	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.12	Unitil Corporation Tax Deferred Savings and Investment Plan—Trust Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2004
10.13***	Amended and Restated Employment Agreement effective as of November 1, 2009 by and between Unitil Corporation and Robert G. Schoenberger.	Exhibit 10.1 to Form 8-K dated September 23, 2009
10.14	Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008.	Exhibit 10.1 to Form 8-K dated November 26, 2008
10.15	Amendment Agreement dated as of January 2, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008.	Exhibit 10.1 to Form 8-K dated January 2, 2009
10.16	Amendment Agreement dated as of October 13, 2009 to the Credit Agreement between Unitil Corporation and Bank of America, N.A. dated November 26, 2008.	Exhibit 10.1 to Form 8-K dated October 13, 2009
10.17	Fourth Amendment Agreement dated October 8, 2010 by and among Unitil Corporation and Bank of America, N.A.	Exhibit 10.5 to Form 8-K dated October 8, 2010
10.18	Credit Agreement between Unitil Corporation and Royal Bank of Canada dated December 1, 2008.	Exhibit 10.2 to Form 8-K dated November 26, 2008
10.19	Transition Services Agreement between Unitil Corporation and NiSource, Inc. dated December 1, 2008.	Exhibit 10.3 to Form 8-K dated November 26, 2008
10.20	Parent Guaranty of Unitil Corporation for the Granite State 7.15% Senior Notes due December 15, 2018.	Exhibit 10.1 to Form 8-K dated December 15, 2008
10.21	Unitil Corporation—Compensation of Directors.	Filed herewith
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
16.1	Letter Re: Change in Certifying Accountant	Exhibit 16.1 to Form 8-K dated September 22, 2010
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	Filed herewith
23.2	Consent of Independent Registered Public Accounting Firm.	Filed herewith

Exhibit Number	Description of Exhibit	Reference*
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith
99.1	Unitil Corporation Press Release Dated February 3, 2011 Announcing Earnings for the Quarter and Year Ended December 31, 2010.	Filed herewith
101.INS	XBRL Instance Document.	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema Document.	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	Filed herewith
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	Filed herewith
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

** In accordance with Item 601(b)(4)(iii)(A) of Federal Securities Regulation S-K, the instrument defining the debt of the Registrant and its subsidiary, described above, has been omitted but will be furnished to the Commission upon request.

*** These exhibits represent a management contract or compensatory plan.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 3, 2011

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board of Directors,
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 3, 2011
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 3, 2011
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	February 3, 2011
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 3, 2011
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 3, 2011
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 3, 2011
/s/ WILLIAM D. ADAMS **William D. Adams**	Director	February 3, 2011
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 3, 2011
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 3, 2011
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 3, 2011
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 3, 2011
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 3, 2011
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	February 3, 2011

EXHIBIT INDEX

Exhibit No.	Description
10.21	Unitil Corporation—Compensation of Directors
11.1	Computation in Support of Earnings per Share
12.1	Computation in Support of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Registrant
23.1	Consent of Independent Registered Public Accounting Firm
23.2	Consent of Independent Registered Public Accounting Firm
31.1-31.3	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Unitil Corporation Press Release Dated February 3, 2011 Announcing Earnings for the Quarter and Year Ended December 31, 2010.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 11.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF EARNINGS PER SHARE

	Year Ended December 31,		
	2010	2009	2008
EARNINGS PER SHARE (000's, except per share data)			
Net Income	**$ 9,616**	$10,049	$9,735
Less: Dividend Requirements on Preferred Stock	**132**	134	135
Net Income Applicable to Common Stock	**$ 9,484**	$ 9,915	$9,600
Average Number of Common Shares Outstanding—Basic	**10,823**	9,647	5,830
Dilutive Effect of Stock Options and Restricted Stock	**1**	—	—
Average Number of Common Shares Outstanding—Diluted	**10,824**	9,647	5,830
Earnings Per Share—Basic	**$ 0.88**	$ 1.03	$ 1.65
Earnings Per Share—Diluted	**$ 0.88**	$ 1.03	$ 1.65

Exhibit 12.1

UNITIL CORPORATION

COMPUTATION IN SUPPORT OF RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2010	2009	2008	2007	2006
(000's, except ratios)					
Earnings:					
Net Income, per Consolidated Statement of Earnings	**$ 9,616**	$10,049	$ 9,735	$ 8,746	$ 8,033
Federal and State Income Taxes included in Operations	**4,464**	5,220	4,450	4,482	4,266
Interest on Long-Term Debt	**19,664**	17,961	11,795	10,919	9,404
Amortization of Debt Discount Expense	**307**	233	151	136	112
Other Interest	**2,015**	2,474	1,156	1,949	1,675
Total	**$36,066**	$35,937	$27,287	$26,232	$23,490
Fixed Charges:					
Interest of Long-Term Debt	**$19,664**	$17,961	$11,795	$10,919	$ 9,404
Amortization of Debt Discount Expense	**307**	233	151	136	112
Other Interest	**2,015**	2,474	1,156	1,949	1,675
Pre-tax Preferred Stock Dividend Requirements	**194**	208	199	213	208
Total	**$22,180**	$20,876	$13,301	$13,217	$11,399
Ratio of Earnings to Fixed Charges	**1.63**	1.72	2.05	1.98	2.06

Exhibit 21.1

Subsidiaries of Registrant

The Company or the registrant has eight wholly-owned subsidiaries, seven of which are corporations organized under the laws of the State of New Hampshire: Unitil Energy Systems, Inc., Northern Utilities, Inc., Granite State Gas Transmission, Inc., Unitil Power Corp., Unitil Realty Corp., Unitil Resources, Inc. and Unitil Service Corp. The eighth, Fitchburg Gas and Electric Light Company, is organized under the laws of the State of Massachusetts. Usource, Inc., which is a corporation organized under the laws of the State of Delaware, is a wholly-owned subsidiary of Unitil Resources, Inc. Usource, Inc. is the sole member of Usource L.L.C., which is a corporation organized under the laws of the State of Delaware.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements of Unitil Corporation and subsidiaries on Form S-3 (File No. 333-168394 effective July 29, 2010), Form S-3 (File No. 333-158537 effective April 29, 2009), Form S-3 (File No. 333-152823 effective December 5, 2008), Form S-8 (File No. 333-114978 effective April 29, 2004) and on Form S-8 (File No. 333-42266 effective July 26, 2000) of our report dated February 3, 2011, relating to the consolidated financial statements of Unitil Corporation and subsidiaries (the Company) as of December 31, 2010 and the year ending December 31, 2010 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, appearing in the Annual Report of the Company on Form 10-K for the year ended December 31, 2010.

/s/ McGladrey & Pullen, LLP
Boston, Massachusetts
February 3, 2011

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements of Unitil Corporation and subsidiaries on Form S-3 (File No. 333-168394 effective July 29, 2010), Form S-3 (File No. 333-158537 effective April 29, 2009), Form S-3 (File No. 333-152823 effective December 5, 2008), Form S-8 (File No. 333-114978 effective April 29, 2004), and on Form S-8 (File No. 333-42266 effective July 26, 2000) of our report dated February 10, 2010, relating to the consolidated financial statements of Unitil Corporation and subsidiaries (the Company) as of December 31, 2009 and the two years ending December 31, 2009, appearing in the Annual Report of the Company on Form 10-K for the year ended December 31, 2010.

/s/ Caturano and Company, Inc.
Boston, Massachusetts
February 3, 2011

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 3, 2011

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 3, 2011

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this annual report on Form 10-K of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 3, 2011

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Unitil Corporation (the "Company") on Form 10-K for the year ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	February 3, 2011
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	February 3, 2011
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	February 3, 2011

Exhibit 99.1

Unitil

Contact: David Chong – Investor Relations
Phone: 603-773-6499
Email: chong@unitil.com

Alec O'Meara – Media Relations
Phone: 603-773-6404
Email: omeara@unitil.com

Unitil Reports Year-End Earnings

Hampton, NH – February 3, 2011: Unitil Corporation (NYSE: UTL) (www.unitil.com) today announced Earnings Applicable to Common Shareholders (Earnings) of $9.5 million, or $0.88 per share for the full year of 2010. This compares to Earnings of $9.9 million, or $1.03 per share in 2009.

The Company also announced Earnings of $5.2 million, or $0.48 per share for the fourth quarter of 2010, compared to Earnings of $1.2 million, or $0.11 per share in the fourth quarter of 2009. The results for 2009 include a non-recurring accounting charge in the fourth quarter for a regulatory order in Massachusetts requiring the refund $4.9 million of natural gas supply costs. The Company has appealed this order to the Massachusetts Supreme Judicial Court and anticipates a ruling in late 2011.

"While 2010 full year results were adversely impacted by a warm winter heating season, we were pleased to see a strong increase in electric sales year over year as well as higher gas sales in the fourth quarter this year, reflecting signs of an improving regional economy," said Bob Schoenberger, Unitil's Chairman and Chief Executive Officer. "The increase in sales combined with the resetting of rates in all of our distribution utilities by the end of 2011 will strengthen the Company's financial position to the benefit of our customers and shareholders."

Electric sales margin increased $4.8 million in 2010 compared to 2009. The increase in electric sales margin reflects higher electric kilowatt-hour (kWh) sales and an electric rate increase implemented in July 2010 for Unitil Energy Systems, Inc. (Unitil Energy), the Company's New Hampshire electric operating utility. The increase in electric sales reflects higher than average summer temperatures in the Company's utility service territories in 2010 coupled with an improving regional economy. According to ISO-New England, the electric transmission grid operator for the New England region, July of 2010 was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month. On a weather-normalized basis, kWh sales in 2010 increased approximately 1.6% year over year and 2.9% in the fourth quarter compared to 2009.

Natural gas sales margin increased $2.3 million in 2010 compared to 2009, reflecting the effect of the ordered refund of $4.9 million of natural gas supply costs recorded in 2009, discussed above. Absent the effect of this refund, natural gas sales margin decreased $2.6 million in 2010 compared to 2009, principally due to the milder winter heating season in the early part of 2010 compared to 2009. Heating Degree Days in 2010 were 9% fewer than in the prior year. On a weather-normalized basis, natural gas therm sales for the full year of 2010 were essentially flat with therm sales in 2009 and increased approximately 2% in the fourth quarter.

Selected Financial Data for 2010 and 2009 is presented in the following table:

Unitil Corporation – Condensed Financial Data
(Millions, except Per Share data)

	(unaudited) Three Months Ended December 31,			Twelve Months Ended December 31,		
	2010	**2009**	**Change**	2010	2009	Change
Gas Therm Sales:						
Residential	8.2	7.6	7.9%	35.1	36.7	(4.4%)
Commercial/Industrial	36.9	35.9	2.8%	137.8	142.0	(3.0%)
Total	**45.1**	**43.5**	**3.7%**	**172.9**	**178.7**	**(3.2%)**
Electric kWh Sales:						
Residential	156.5	152.1	2.9%	681.2	645.9	5.5%
Commercial/Industrial	242.0	234.6	3.2%	1,009.9	972.9	3.8%
Total	**398.5**	**386.7**	**3.1%**	**1,691.1**	**1,618.8**	**4.5%**
Gas Revenues	$ 47.9	$ 41.8	$ 6.1	$ 150.1	$ 152.8	$ (2.7)
Purchased Gas	29.6	29.6	—	93.3	98.3	(5.0)
Gas Sales Margin	**18.3**	**12.2**	**6.1**	**56.8**	**54.5**	**2.3**
Electric Revenues	48.8	46.6	2.2	203.7	209.9	(6.2)
Purchased Electricity	33.0	33.1	(0.1)	143.7	154.7	(11.0)
Electric Sales Margin	**15.8**	**13.5**	**2.3**	**60.0**	**55.2**	**4.8**
Usource Sales Margin	**1.2**	**1.1**	**0.1**	**4.6**	**4.3**	**0.3**
Total Sales Margin:	**35.3**	**26.8**	**8.5**	**121.4**	**114.0**	**7.4**
Operation & Maintenance Expenses	11.9	10.3	1.6	48.8	44.7	4.1
Depreciation, Amortization, Taxes & Other	13.6	12.0	1.6	45.0	43.6	1.4
Interest Expense, Net	4.6	3.3	1.3	18.1	15.8	2.3
Earnings Applicable to Common Shareholders:	**$ 5.2**	**$ 1.2**	**$ 4.0**	**$ 9.5**	**$ 9.9**	**$ (0.4)**
Earnings Per Share	**$ 0.48**	**$ 0.11**	**$0.37**	**$ 0.88**	**$ 1.03**	**$(0.15)**

Usource, the Company's non-regulated energy brokering business, recorded revenues of $4.6 million in 2010, an increase of $0.3 million compared to 2009.

Total Operation & Maintenance (O&M) expenses increased $4.1 million in 2010 compared to 2009. The changes in O&M expenses reflect higher utility operating costs. O&M expenses in 2010 also reflect the full integration of Northern Utilities Inc. (Northern Utilities) and Granite State Gas Transmission Inc. (Granite State) into the Company's consolidated operating results. In 2009, the Company recognized professional fees of approximately $3.0 million related to regulatory and legal matters concerning the Company's preparation and response to the devastating ice storm that struck the New England region in December 2008.

Depreciation and Amortization expense increased $1.5 million in 2010 compared to 2009, reflecting higher depreciation on normal utility plant additions partially offset by lower net amortization expense in the current year.

Interest Expense, Net increased $2.3 million in 2010 compared to 2009. The increase is primarily due to the issuance of $40 million of long-term notes by Unitil Energy Systems, Inc. and Northern Utilities in March 2010.

Federal and State Income Taxes decreased by $0.9 million in 2010 due to lower pre-tax income in 2010 compared to 2009.

All other expenses increased $0.8 million in 2010 compared to 2009, primarily reflecting higher property taxes and payroll taxes.

At its January 2011 meeting, the Unitil Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. Unitil paid common dividends of $1.38 in 2010.

Earnings per share for 2010 are not directly comparable with 2009 due to the issuance of 5.0 million common shares between December 2008 and June 2009 to complete the financing associated with the Company's acquisition of Northern Utilities and Granite State in December 2008.

The Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Rate Case Activity

On April 15, 2010, Unitil Energy filed for a distribution base rate increase of $10.1 million. The Company's filing also included a proposed long-term rate plan establishing step adjustments for future utility plant investments and an enhanced reliability and vegetation management programs. On June 29, 2010, the New Hampshire Public Utilities Commission (NHPUC) issued an order approving a temporary rate increase for Unitil Energy of $5.2 million effective July 1, 2010. Once permanent rates are approved by the NHPUC, they will be reconciled to the date temporary rates were ordered. The Company is currently engaged in settlement procedures regarding the permanent rate level and a long-term rate plan. A hearing in this matter is scheduled for early February 2011.

On November 30, 2010 the Company's interstate natural gas transmission pipeline, Granite State, filed a rate settlement agreement, which provides for an increase of approximately $1.7 million in annual revenue effective January 1, 2011. This settlement agreement was approved by the Federal Energy Regulatory Commission on January 31, 2011.

On January 14, 2011, the Company's Massachusetts operating utility, Fitchburg Gas and Electric Light Company (Fitchburg), filed a comprehensive revenue decoupling proposal and a request for distribution rate increases of $7.1 million for its electric division and $4.4 million of its gas division. The Company's filing also includes a rate-impact mitigation alternative for the electric division that would offset the distribution revenue increase through a corresponding decrease in Fitchburg's Transition Charge. The Transition Charge is the means by which Fitchburg recovers its power supply-related stranded costs and other restructuring-related regulatory assets. Any offsetting decrease in the Transition Charge would allow for the recovery of the restructuring related stranded costs over an extended term. The Company's revenue decoupling proposal is modeled closely on decoupling proposals already approved by the Massachusetts Department of Public Utilities (MDPU) for other utilities operating in the Commonwealth of Massachusetts and is intended to align the Company's interests with important public policy objectives concerning energy efficiency, energy reliability, national energy security and protecting the environment. The MDPU issued an order suspending and deferring the use of the rates until August 2, 2011, pending an investigation and analysis of the Company's filing.

Northern Utilities, the Company's gas distribution utility operating in the states of New Hampshire and Maine, is currently expected to file base rate cases for both its New Hampshire and Maine divisions in the second quarter of 2011. The Company will announce the amount of the requested rate increases and other related information after the filing of the distribution rate cases.

The Company will hold a quarterly conference call to discuss fourth quarter and full year 2010 results on Thursday, February 3, 2011 at 2:00 p.m. Eastern Time. This call is being webcast by Thomson Financial and can be accessed in the Investor Relations section of Unitil Corporation's website, www.unitil.com.

About Unitil

Unitil provides for the necessities of life, safely and reliably delivering natural gas and electricity throughout northern New England. We are committed to the communities we serve and to developing people, business practices, and technologies that lead to dependable, more efficient energy. Unitil is a public utility holding company with affiliates that include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc., and Granite State Gas Transmission, Inc. Together, Unitil's operating utilities serve approximately 100,900 electric customers and 70,800 natural gas customers. Other subsidiaries include Unitil Service Corp. and Usource, Unitil's non-regulated business segment. For more information about our people, technologies, and community involvement please visit www.unitil.com.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended March 31, 2009

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes _ No _

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer___ Accelerated filer__X__

Non-accelerated filer___ Smaller reporting company___
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 27, 2009
Common Stock, No par value	8,106,967 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended March 31, 2009

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the Federal Energy Regulatory Commission (the "FERC") under the Energy Policy Act of 2005.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly owned distribution utilities: (i) Unitil Energy Systems, Inc. (Unitil Energy), which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the city of Concord, New Hampshire; (ii) Fitchburg Gas and Electric Light Company (Fitchburg), which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and (iii) Northern Utilities, Inc. (Northern Utilities), which provides natural gas service in southeastern New Hampshire, including the city of Portsmouth, and portions of southern and central Maine, including the city of Portland. In addition, Unitil is the parent company of Granite State Gas Transmission, Inc. (Granite State), an interstate natural gas transmission pipeline company that principally provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory.

The Company's distribution utilities serve approximately 100,300 electric customers and 69,300 natural gas customers in their service territory. The Company's distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in Net Utility Plant of $428.5 million at March 31, 2009. The Company does not own or operate electric generating facilities or major transmission facilities and substantially all of the Company's utility assets are dedicated to the local delivery of electricity and natural gas to its customers. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil's business strategy is to be a leader in the reliable and cost effective management of a growing level of local electric and natural gas distribution assets. The Company's growth initiatives include evaluation of organic growth opportunities as well as strategic acquisitions. As part of this growth strategy, on December 1, 2008, Unitil purchased (i) all of the outstanding capital stock of Northern Utilities from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State and Unitil (the "Acquisitions"). Bay State is a wholly owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt.

A fifth wholly owned subsidiary, Unitil Power Corp. (Unitil Power), formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

The Company also has three other wholly owned subsidiaries: Unitil Service Corp. (Unitil Service); Unitil Realty Corp. (Unitil Realty); and Unitil Resources, Inc. (Unitil Resources). Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, "Usource") are indirect subsidiaries that are wholly owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, in regards to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and the Maine Public Utilities Commission (MPUC). Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party suppliers. A majority of Unitil's largest commercial and industrial (C&I) customers purchase their electric and natural gas supplies from third party suppliers. However, most residential and small customers continue to purchase their electric and natural gas supplies through Unitil's distribution utilities. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features. For additional discussion, please refer to Unitil's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 18, 2009.

CAUTIONARY STATEMENT

This report and the documents the Company incorporates by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's and its management's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Part II, Item 1A (Risk Factors) and the following:

- The Company's ability to integrate the business, operations and personnel of Northern Utilities and Granite State and to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;

- General economic conditions, including recent distress in the financial markets that has had an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of the Company's counterparty obligations, including those of Unitil's insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended March 31, 2009 and March 31, 2008 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Part I, Item 1 of this report.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales. Specifically, the Company expects consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders was $9.1 million for the first quarter of 2009, an increase of $5.8 million over 2008 first quarter earnings of $3.3 million. Earnings per common share (EPS) were $1.14 for the three months ended March 31, 2009, an improvement of $0.57 per share over the first quarter of 2008. Earnings in the first quarter of 2009 reflect the acquisition, on December 1, 2008, of Northern Utilities and Granite State.

Natural gas sales margin increased $18.1 million in the three months ended March 31, 2009 compared to the same period in 2008. This increase primarily reflects the contribution by Northern Utilities, the Company's recently acquired local gas distribution utility. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas increased 6.0% in the three months ended March 31, 2009 compared to the same period in 2008, reflecting increases of 6.3% and 5.9% in sales to residential and C&I customers, respectively. Sales in the first three months of 2009 reflect a colder winter heating season this year and increased usage of natural gas by C&I customers for production operations. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

Electric sales margin increased $1.3 million in the three months ended March 31, 2009 compared to the same period in 2008, reflecting higher electric base rates in the current quarter, partially offset by lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 4.7% in the three months ended March 31, 2009 compared to the same period in 2008 driven by lower average usage per customer reflecting the continued economic slowdown and energy conservation.

Total Operation & Maintenance (O&M) expenses increased $5.7 million in the three months ended March 31, 2009 compared to the same period in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $2.1 million of the increase. In addition, higher year over year compensation and employee benefit expenses of $0.7 million and higher utility operating costs of $0.4 million, partially offset by lower professional fees of $0.3 million, contributed to the increase in O&M expenses. The increase in O&M expenses also reflects higher insurance costs in 2009 compared to 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Depreciation, Amortization, Taxes and Other expenses increased $5.8 million in the three months ended March 31, 2009 compared to the same period in 2008. The increase primarily reflects the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs.

Interest Expense, Net increased $2.2 million in the three months ended March 31, 2009 compared to the same period in 2008. The addition of Northern Utilities and Granite State accounted for $1.7 million of the increase, reflecting the issuance of long-term notes by Northern Utilities and Granite State in December 2008. In addition to this increase in Interest Expense, Net reflects higher average borrowings in the current quarter.

Usource, our non-regulated energy brokering business, recorded revenues of $1.1 million in the first quarter of 2009, an increase of $0.1 million over the first quarter of 2008. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

On December 11 and 12, 2008, a severe ice storm struck the New England region, creating extended power outages for many residents of Massachusetts and New Hampshire, including Unitil's electric customers in New Hampshire and the greater Fitchburg, Massachusetts service territory. Based on its preliminary assessment, the Company has accrued and deferred, excluding capital construction expenditures, approximately $10 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations.

In December 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. In January 2009, the underwriters exercised the over-allotment option associated with this offering and purchased an additional 270,000 shares of the Company's common stock. The Company used net proceeds of $41.9 million from these issuances to repay a portion of the bank financing for the Company's acquisitions of Northern Utilities and Granite State and to repay other short-term indebtedness. Overall, the positive results of operations and net income are reflected over a higher number of average shares outstanding year over year.

In 2008, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2009 and March, 2009 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three months ended March 31, 2009 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

The Company's Total Assets increased by $255.6 million as of March 31, 2009 compared to March 31, 2008. The increase in Total Assets was primarily due to the inclusion of the acquisitions of Northern Utilities and Granite State and to capital expenditures related to Unitil Energy's and Fitchburg's electric and gas distribution systems. The Company's Total Capitalization increased by $138.0 million as of March 31, 2009 compared to March 31, 2008 reflecting the issuance of common shares by the Company as part of its financing of the acquisitions of Northern Utilities and Granite State (See Note 3 to the accompanying Consolidated Financial Statements) and the issuance and sale of Senior Unsecured Notes by Northern Utilities and Granite State (See Note 4 to the accompanying Consolidated Financial Statements). The Company's Total Liabilities increased $117.6 million primarily due to the acquisitions of Northern Utilities and Granite State.

Gas Sales, Revenues and Margin

Therm Sales – Overall, Unitil's total therm sales of natural gas increased in the three months ended March 31, 2009 compared to the same period in 2008. This increase primarily reflects the contribution of sales by Northern

Utilities. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas increased 6.0% in the three months ended March 31, 2009 compared to the same period in 2008, reflecting increases of 6.3% and 5.9% in sales to residential and C&I customers, respectively. The higher sales in the first three months of 2009 reflect a colder winter heating season this year and increased usage of natural gas by C&I customers for production operations. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

The following table details total firm therm sales for the three months ended March 31, 2009 and 2008, by major customer class:

Therm Sales (millions) (a)

	Three Months Ended March 31,			
	2009	2008	Change	% Change
Residential	**19.3**	4.8	14.5	302.1%
Commercial/Industrial	**58.1**	6.8	51.3	754.4%
Total	**77.4**	11.6	65.8	567.2%

(a) 2009 Therm Sales include Northern Utilities, acquired on December 1, 2008.

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three months ended March 31, 2009 and 2008:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended March 31,			
	2009	2008	$ Change	% Change[1]
Gas Operating Revenue:				
Residential	**$ 30.4**	$ 8.0	$ 22.4	156.6%
Commercial / Industrial	**42.0**	6.3	35.7	249.7%
Total Gas Operating Revenue	**$ 72.4**	$ 14.3	$ 58.1	406.3%
Cost of Gas Sales:				
Purchased Gas	**$ 48.4**	$ 9.0	$ 39.4	275.5%
Conservation & Load Management	**0.6**	---	0.6	4.2%
Gas Sales Margin	**$ 23.4**	$ 5.3	$ 18.1	126.6%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $58.1 million in the three months ended March 31, 2009 compared to the same period in 2008. This increase primarily reflects the natural gas sales for Northern Utilities. In addition to the contribution from Northern Utilities, the increase in gas operating revenues reflects a 6.0% increase in natural gas sales. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and Conservation & Load Management (C&LM) in Operating Expenses. The increase in Total Gas Operating Revenues in the first quarter of 2009 reflects higher Purchased Gas costs of $39.4 million, higher C&LM revenues of $0.6 million and higher gas sales margin of $18.1 million.

The Purchased Gas and C&LM component of Gas Operating Revenues increased $40.0 million in the three months ended March 31, 2009 compared to the same period in 2008. This increase primarily reflects the natural gas sales for Northern Utilities. In addition to the contribution from Northern Utilities, the increase reflects the higher sales of natural gas, discussed above. Purchased Gas revenues include the recovery of the cost of gas supply as well as other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $18.1 million in the three months ended March 31, 2009 compared to the same period in 2008. This increase was driven by the higher sales of natural gas, discussed above.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – In the first quarter of 2009, Unitil's total electric kWh sales decreased 4.7% compared to the first quarter of 2008. Sales to residential and C&I customers decreased 1.0% and 7.3%, respectively, in the first quarter of 2009 compared to the same period in 2008. The lower kWh sales in 2009 compared to 2008 were primarily driven by lower average usage by the Company's customers reflecting the continued economic slowdown and energy conservation.

The following table details total kWh sales for the three months ended March 31, 2009 and 2008 by major customer class:

kWh Sales (millions)

	Three Months Ended March 31,			
	2009	2008	Change	% Change
Residential	**180.6**	182.4	(1.8)	(1.0%)
Commercial/Industrial	**242.1**	261.1	(19.0)	(7.3%)
Total	**422.7**	443.5	(20.8)	(4.7%)

Electric Operating Revenues and Sales Margin - The following table details total Electric Operating Revenues and Sales Margin for the three months ended March 31, 2009 and 2008:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended March 31,			
	2009	2008	$ Change	% Change[1]
Electric Operating Revenue:				
Residential	**$ 33.2**	$ 30.3	$ 2.9	5.1%
Commercial / Industrial	**28.9**	26.3	2.6	4.6%
Total Electric Operating Revenue	**$ 62.1**	$ 56.6	$ 5.5	9.7%
Cost of Electric Sales:				
Purchased Electricity	**$ 47.2**	$ 42.9	$ 4.3	7.6%
Conservation & Load Management	**0.5**	0.6	(0.1)	(0.2%)
Electric Sales Margin	**$ 14.4**	$ 13.1	$ 1.3	2.3%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues increased by $5.5 million, or 9.7%, in the three months ended March 31, 2009 compared to the same period in 2008. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The increase in Total Electric Operating Revenues in the three months ended March 31, 2009 reflects higher Purchased Electricity costs of $4.3 million and higher electric sales margin of $1.3 million, partially offset by lower C&LM revenues of $0.1 million.

The Purchased Electricity and C&LM component of Total Electric Operating Revenues increased a combined $4.2 million, or 7.4%, in the three months ended March 31, 2009 compared to the same period in 2008, reflecting higher electric commodity prices, partially offset by lower electric kWh sales. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $1.3 million in the three months ended March 31, 2009 compared to the same period in 2008, reflecting higher electric base rates in the current quarter, partially offset by lower sales volumes. Lower sales reflect lower average usage by the Company's customers reflecting the continued economic slowdown and energy conservation.

Operating Revenue - Other

The following table details total Other Operating Revenue for the three months ended March 31, 2009 and 2008:

Other Operating Revenue (Millions)

	Three Months Ended March 31,			
	2009	2008	$ Change	% Change
Other	**$ 1.1**	$ 1.0	$ 0.1	10.0%
Total Other Operating Revenue	**$ 1.1**	$ 1.0	$ 0.1	10.0%

Total Other Operating Revenue increased $0.1 million, or 10.0%, in the three month period ended March 31, 2009 compared to the same period in 2008. The increase was the result of growth in revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Gas – Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $39.4 million in the three month period ended March 31, 2009 compared to the same period in 2008. This increase primarily reflects the natural gas supply purchases for Northern Utilities, which were not included in the prior year period. In addition to the natural gas supply purchases for Northern Utilities, the increase in Purchased Gas reflects increased gas supply costs related to the higher sales of natural gas, discussed above which were driven by a colder winter heating season this year and increased usage of natural gas in C&I customers' production operations. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Electricity – Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity increased $4.3 million, or 10.0%, in the three month period ended March 31, 2009 compared to the same period in 2008, reflecting higher electric commodity prices and a decrease in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by lower electric kWh sales. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not affect earnings.

Operation and Maintenance (O&M) - O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. Total O&M expenses increased $5.7 million in the three months ended March 31, 2009 compared to the same period in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $2.1 million of the increase. In addition, higher year over year compensation and employee benefit expenses of $0.7 million and higher utility operating costs of $0.4 million, partially offset by lower professional fees of $0.3 million, contributed to the increase in O&M expenses. The increase in O&M expenses also reflects higher insurance costs in 2009 compared to 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Conservation & Load Management – Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total Conservation & Load Management expenses increased by $0.5 million in the three months ended March 31, 2009 compared to the same period in 2008. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense increased $1.1 million, or 21.2%, in the three months ended March 31, 2009 compared to the same period in 2008. The increase primarily reflects the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs.

Local Property and Other Taxes - Local Property and Other Taxes increased by $1.3 million, or 76.5%, in the three months ended March 31, 2009 compared to the same period in 2008. The increase primarily reflects the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes - Federal and State Income Taxes were higher by $3.5 million for the three months ended March 31, 2009 compared to the same period in 2008 reflecting higher pre-tax earnings in the current quarter.

Other Non-Operating Expense

Other Non-operating Expenses decreased by $0.1 million in the three month period ended March 31, 2009 compared to the same period in 2008. This change reflects an adjustment of $0.1 million recorded in the first quarter of 2008 in conjunction with the Company's approved electric base distribution rate increase in Massachusetts.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (millions)	Three Months Ended March 31,		
	2009	2008	Change
Interest Expense			
Long-term Debt	**$ 4.6**	$ 2.9	$ 1.7
Short-term Debt	**1.1**	0.3	0.8
Regulatory Liabilities	**---**	---	---
Subtotal Interest Expense	**5.7**	3.2	2.5
Interest (Income)			
Regulatory Assets	**(0.7)**	(0.6)	(0.1)
AFUDC and Other	**(0.2)**	---	(0.2)
Subtotal Interest (Income)	**(0.9)**	(0.6)	(0.3)
Total Interest Expense, Net	**$ 4.8**	$ 2.6	$ 2.2

Interest Expense, Net increased $2.2 million in the three months ended March 31, 2009 compared to the same period in 2008. The addition of Northern Utilities and Granite State accounted for $1.7 million of the increase, reflecting the issuance of long-term notes by Northern Utilities and Granite State in December 2008. In addition to this increase in Interest Expense, Net reflects higher average borrowings in the current quarter.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

At March 31, 2009, Unitil had $39.1 million outstanding under a bank financing facility utilized in connection with the financing of the acquisition of Northern Utilities and Granite State on December 1, 2008. The Company expects to repay the outstanding balance under this facility prior to its maturity date of November 1, 2009 by issuing additional equity or debt.

In addition, at March 31, 2009, the Company had $48.6 million in short-term debt outstanding through bank borrowings under its revolving credit agreement (excluding amounts borrowed under the bank financing facility discussed above). The revolving credit agreement contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of March 31, 2009, the Company was in compliance with financial covenants contained in the revolving credit agreement.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2009, there were approximately $27.1 million of guarantees outstanding and these guarantees extend through December 31, 2010.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of March 31, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.6 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Cash Flows

On December 1, 2008, the Company acquired Northern Utilities and Granite State. Cash flow results for the first quarter of 2009 include the activity for the acquired companies. Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for the three months ended March 31, 2009 compared to the same period in 2008.

	Three Months Ended March 31,	
	2009	**2008**
Cash Provided by Operating Activities	$ **5.0**	$ 7.9

Cash Provided by Operating Activities - Cash Provided by Operating Activities was $5.0 million during the three months ended March 31, 2009, a decrease of $2.9 million over the comparable period in 2008. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes increased by $5.3 million, and uses of cash for working capital increased $4.7 million, while all other sources and uses of cash from Operating Activities resulted in net use of cash of $3.5 million in the first three months of 2009 compared to 2008.

	Three Months Ended March 31,	
	2009	**2008**
Cash (Used in) Investing Activities	$ **(18.0)**	$ (4.5)

Cash (Used in) Investing Activities - Cash (Used in) Investing Activities was $18.0 million for the three months ended March 31, 2009, an increase in capital spending of $13.5 million over the comparable period in 2008. Of this amount, $9.9 million is related to expenditures for the December 2008 ice storm, and $2.5 million is related to capital expenditures for Northern Utilities.

	Three Months Ended March 31,	
	2009	2008
Cash Provided by (Used in) Financing Activities	$ **16.0**	$ (4.0)

Cash Provided by (Used in) Financing Activities - Cash (Used in) Financing Activities was $16.0 million in the three months ended March 31, 2009. Proceeds from the issuance of Common Stock of $5.4 million reflect the exercise of an over-allotment option by underwriters to purchase additional shares related to the Company's December 2008 public offering. Additional short-term borrowings provided $13.6 million for a total of $19.0 million of cash in the first three months of 2009. Uses of cash of $3.0 million primarily reflect Unitil's regular quarterly dividend payments on Common and Preferred Stock, and the scheduled repayment of long-term debt.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 18, 2009.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy is regulated by the FERC and the NHPUC. Fitchburg is regulated by the FERC and the MDPU. Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)	March 31, 2009	March 31, 2008	December 31, 2008
Energy Supply Contract Obligations	**$ 47.7**	$ 67.7	$ 52.7
Deferred Restructuring Costs	**28.2**	29.6	28.3
Generation-related Assets	**0.6**	1.4	0.8
Subtotal – Restructuring Related Items	**76.5**	98.7	81.8
Retirement Benefit Obligations	**45.3**	35.1	45.5
Income Taxes	**15.6**	14.2	16.0
Environmental Obligations	**20.9**	10.9	19.7
Other	**12.0**	3.1	10.1
Total Regulatory Assets	**$ 170.3**	$ 162.0	$ 73.1
Less: Current Portion of Regulatory Assets(1)	**26.7**	22.8	26.9
Regulatory Assets - noncurrent	**$ 143.6**	$ 139.2	$ 146.2

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations - The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans”, (SFAS No. 158), an amendment of SFAS No. 87, “Employers’ Accounting for Pensions”, SFAS No. 88, “Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits,” SFAS No. 106, “Employers’ Accounting for Postretirement Benefits other than Pensions” and SFAS No. 132(R), “Employers’ Disclosures about Pensions and Other Postretirement Benefits.” SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company’s reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company’s RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company’s RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company’s RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2008 and 2007, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2008 and 2007, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $675,000 and $690,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $531,000 and $539,000, respectively. (See Note 8 to the accompanying Consolidated Financial Statements).

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company’s current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company’s consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, “Accounting for Income Taxes” (SFAS No. 109) and under FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48), an interpretation of FAS 109.

Depreciation - Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company’s fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies - The Company’s accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of March 31, 2009, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

As of March 31, 2009, 149 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two of these agreements expired on March 31, 2009, and these agreements were successfully renegotiated, with a new combined agreement that will expire on March 31, 2012. Two agreements expire on May 31, 2010, and one agreement expires on June 5, 2010. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rates on the Company's short-term borrowings for the three months ended March 31, 2009 and March 31, 2008 were 4.78% and 3.84%, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions, except common shares and per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2009	2008
Operating Revenues		
Gas	**$ 72.4**	$ 14.3
Electric	**62.1**	56.6
Other	**1.1**	1.0
Total Operating Revenues	**135.6**	71.9
Operating Expenses		
Purchased Gas	**48.4**	9.0
Purchased Electricity	**47.2**	42.9
Operation and Maintenance	**10.4**	4.7
Conservation & Load Management	**1.1**	0.6
Depreciation and Amortization	**6.3**	5.2
Provisions for Taxes:		
Local Property and Other	**3.0**	1.7
Federal and State Income	**5.3**	1.8
Total Operating Expenses	**121.7**	65.9
Operating Income	**13.9**	6.0
Other Non-Operating Expense (Income)	**---**	0.1
Income Before Interest Expense	**13.9**	5.9
Interest Expense, Net	**4.8**	2.6
Net Income	**9.1**	3.3
Less: Dividends on Preferred Stock	**---**	---
Earnings Applicable to Common Shareholders	**$ 9.1**	$ 3.3
Average Common Shares Outstanding – Basic (000's)	**8,018**	5,719
Average Common Shares Outstanding – Diluted (000's)	**8,018**	5,724
Earnings Per Common Share (Basic and Diluted)	**$ 1.14**	$ 0.57
Dividends Declared Per Share of Common Stock	**$ 0.69**	$ 0.69

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) March 31, 2009	March 31, 2008	December 31, 2008
ASSETS:			
Utility Plant:			
Electric	**$ 297.2**	$ 271.3	$ 289.0
Gas	**309.1**	69.2	304.2
Common	**30.4**	27.2	30.5
Construction Work in Progress	**10.4**	4.9	17.7
Total Utility Plant	**647.1**	372.6	641.4
Less: Accumulated Depreciation	**218.6**	123.2	218.6
Net Utility Plant	**428.5**	249.4	422.8
Current Assets:			
Cash	**14.5**	4.0	11.5
Accounts Receivable – Net of Allowance for Doubtful Accounts of $3.7, $1.4 and $3.0	**51.9**	28.9	39.7
Accrued Revenue	**50.0**	38.1	58.9
Gas Inventory	**8.7**	0.6	31.6
Materials and Supplies	**3.1**	1.9	2.7
Prepayments and Other	**2.9**	1.8	5.9
Total Current Assets	**131.1**	75.3	150.3
Noncurrent Assets:			
Regulatory Assets	**143.6**	139.2	146.2
Other Noncurrent Assets	**23.0**	6.7	15.9
Total Noncurrent Assets	**166.6**	145.9	162.1
TOTAL	**$ 726.2**	$ 470.6	$ 735.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) March 31, 2009	(UNAUDITED) March 31, 2008	December 31, 2008
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 148.5**	$ 100.0	$ 139.5
Preferred Stock	**2.0**	2.1	2.0
Long-Term Debt, Less Current Portion	**249.2**	159.6	249.3
Total Capitalization	**399.7**	261.7	390.8
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.4	0.4
Accounts Payable	**29.9**	15.6	36.3
Short-Term Debt	**87.7**	16.7	74.1
Energy Supply Contract Obligations	**21.6**	20.0	42.0
Other Current Liabilities	**36.4**	13.2	35.8
Total Current Liabilities	**176.0**	65.9	188.6
Deferred Income Taxes	**29.1**	31.9	31.1
Noncurrent Liabilities:			
Energy Supply Contract Obligations	**31.2**	47.7	34.6
Retirement Benefit Obligations	**69.7**	49.6	67.4
Environmental Obligations	**11.4**	12.0	12.3
Other Noncurrent Liabilities	**9.1**	1.8	10.4
Total Noncurrent Liabilities	**121.4**	111.1	124.7
TOTAL	**$ 726.2**	$ 470.6	$ 735.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Three Months Ended March 31, 2009	2008
Operating Activities:		
Net Income	**$ 9.1**	$ 3.3
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**6.3**	5.2
Deferred Taxes Provision	**(1.8)**	(0.2)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**(12.2)**	(4.0)
Accrued Revenue	**9.4**	(1.3)
Accounts Payable	**(6.4)**	(2.0)
All other Current Assets and Liabilities	**2.5**	5.3
Other, net	**(1.9)**	1.6
Cash Provided by Operating Activities	**5.0**	7.9
Investing Activities:		
Property, Plant and Equipment Additions	**(18.0)**	(4.5)
Cash (Used in) Investing Activities	**(18.0)**	(4.5)
Financing Activities:		
Proceeds from (Repayment of) Short-Term Debt	**13.6**	(2.1)
Dividends Paid	**(2.8)**	(2.0)
Proceeds from Issuance of Common Stock, net	**5.4**	0.2
Other, net	**(0.2)**	(0.1)
Cash Provided by (Used in) Financing Activities	**16.0**	(4.0)
Net Increase (Decrease) in Cash	**3.0**	(0.6)
Cash at Beginning of Period	**11.5**	4.6
Cash at End of Period	**$ 14.5**	$ 4.0
Supplemental Cash Flow Information:		
Interest Paid	**$ 2.6**	$ 2.1
Income Taxes Paid	**---**	0.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the "Acquisitions"). The purchase price allocation, as disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on February 18, 2009, is preliminary and is subject to change due to several factors, including, but not limited to: (1) changes in the fair values of Northern Utilities' and Granite State's current assets and liabilities as of the date of the acquisition; (2) the actual transition and transaction costs incurred; and (3) changes in the Company's valuation estimates that may be made between now and the time the purchase price allocation is finalized. As of March 31, 2009 there have been no material adjustments to the purchase price allocation.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern and central Maine and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the distribution utilities).

Granite State is a natural gas transportation pipeline, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third -party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service; Unitil Realty; and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three months ended March 31, 2009 are not necessarily indicative of results to be expected for the year ending December 31, 2009. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2008, as filed with the Securities and Exchange Commission (SEC) on February 18, 2008, for a description of the Company's Basis of Presentation.

As discussed above, the Company acquired Northern Utilities and Granite State on December 1, 2008. Accordingly, the operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from the date of acquisition, including the three month period ended March 31, 2009 but not for the three months ended March 31, 2008. See Note 10.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Derivatives – The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases NYMEX futures that correspond to the associated delivery month. Any gains or losses on the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. As a result of the ratemaking process, the Company records gains and losses as regulatory liabilities or assets and recognizes such gains or losses in Purchased Gas when recovered in revenues. The Company's Consolidated Balance Sheets include derivative liabilities related to net unrealized losses on futures contracts in Other Current Liabilities and Noncurrent Liabilities which are offset in Accrued Revenues on the Company's Consolidated Balance Sheets.

Reclassifications – Based on the Company's analysis certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation, principally including the reclassification of $22.8 million of Noncurrent Assets to Current Assets and $20.0 million of Noncurrent Liabilities to Current Liabilities related to current collections and obligations of Regulatory Assets and Regulatory Liabilities for 2008.

Recently Issued Pronouncements – On April 9, 2009, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. FAS 107-1and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments" (FSP FAS 107-1). FSP FAS 107-1 amends FASB Statement No. 107, "Disclosures about Fair Value of Financial Instruments" to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. FSG FAS 107-1 also amends Accounting Principles Board Opinion No. 28, "Interim Financial Reporting", to require those disclosures in summarized financial information at interim reporting periods. FSP FAS 107-1 is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company does not expect that the adoption of FSP FAS 107-1 will have an impact on the Company's Consolidated Financial Statements.

On December 30, 2008, the FASB issued FASB Staff Position No. FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets", (FSP FAS 132(R)-1) to provide guidance on an employers' disclosures about plan assets of a defined benefit pension or other postretirement plan. The disclosures about plan assets required by FSP FAS 132(R)-1 are to be provided for fiscal years ending after December 15, 2009. The Company does not expect that the adoption of the deferred sections of FSP FAS 132(R)-1 will have an impact on the Company's Consolidated Financial Statements.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
03/26/09	05/15/09	05/01/09	$ 0.345
01/15/09	02/16/09	02/02/09	$ 0.345
09/25/08	10/31/08	10/17/08	$ 0.345
06/19/08	08/15/08	08/01/08	$ 0.345
03/20/08	05/15/08	05/01/08	$ 0.345
01/17/08	02/15/08	02/01/08	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

Common Stock

As of August 21, 2008 the Company's common stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's common stock trades under the symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 8,105,540, 5,763,159 and 7,791,617 of common shares outstanding at March 31, 2009, March 31, 2008 and December 31, 2008, respectively.

Unitil Corporation Common Stock Offering – On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. The Company repaid $36.8 million outstanding under the bank financing facility for the Company's acquisitions of Northern Utilities and Granite State with the net proceeds from the sale and issuance of its common stock.

As part of this offering, the Company granted the underwriters a 30-day option to purchase up to an additional 300,000 shares to cover any over-allotments. The underwriters exercised their over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the over-allotment sales were approximately $5.1 million (after payment of the underwriting discount, but excluding estimated offering expenses) and were used to repay a portion of the bank financing for the Company's acquisitions of Northern Utilities and Granite State and to repay other short-term indebtedness. The Company recorded the issuance of the 270,000 shares, the sale proceeds and the increase in Common Equity in January 2009.

The Company currently has 1,730,000 shares of its common stock registered on an effective Registration Statement on Form S-3 under the Securities Act of 1933 and available for public offerings. On April 24, 2009, the Company filed a Registration Statement on Form S-3 for 1,270,000 shares of its common stock. As a result, once this Registration Statement is declared effective, the Company will have 3,000,000 shares of its common stock available for future public offerings, including the 1,730,000 shares carried over from the Company's previously filed Registration Statement.

Dividend Reinvestment and Stock Purchase Plan - During the first quarter of 2009, the Company sold 11,663 shares of its Common Stock, at an average price of $20.29 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $237,000 were used to reduce short-term borrowings.

During the first quarter of 2008, the Company sold 7,596 shares of its Common Stock, at an average price of $27.94 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $212,000 were used to reduce short-term borrowings.

Restricted Stock Plan - The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 17, 2009, 32,260 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $661,007. Compensation expense associated with shares issued under the Plan is recognized ratably as the shares vest and was $0.1 million and $0.1 million for the three months ended March 31, 2009 and 2008, respectively. At March 31, 2009, there was approximately $1.5 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 3.3 years as the shares vest. During the first quarter of 2009, 12,459 restricted shares vested. As of March 31, 2009 there were 52,019 unvested restricted shares.

Preferred Stock

Details on preferred stock at March 31, 2009, March 31, 2008 and December 31, 2008 are shown below:

(Amounts in Millions)

	March 31,		December 31,
	2009	2008	2008
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.9	0.8
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.0**	$ 2.1	$ 2.0

NOTE 4 – LONG-TERM DEBT, CREDIT ARRANGEMENTS AND GUARANTEES

Long-Term Debt

Details on long-term debt at March 31, 2009, March 31, 2008 and December 31, 2008 are shown below ($ Millions):

	March 31, 2009	March 31, 2008	December 31, 2008
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Northern Utilities Senior Notes:			
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	---	30.0
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	---	50.0
Granite State Senior Notes:			
7.15% Senior Notes, Due December 15, 2018	**10.0**	---	10.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due Through August 1, 2017	**4.6**	5.0	4.7
Total Long-Term Debt	**249.6**	160.0	249.7
Less: Current Portion	**0.4**	0.4	0.4
Total Long-term Debt, Less Current Portion	**$ 249.2**	$ 159.6	$ 249.3

The fair value of the Company’s long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at March 31, 2009 is estimated to be approximately $232 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

Credit Arrangements

At March 31, 2009, Unitil had $39.1 million outstanding under a bank financing facility utilized in connection with the financing of the acquisition of Northern Utilities and Granite State on December 1, 2008. The Company expects to repay the outstanding balance under this facility prior to its maturity date of November 1, 2009 by issuing additional equity or debt.

In addition, at March 31, 2009, the Company had $48.6 million in short-term debt outstanding through bank borrowings under its revolving credit agreement (excluding amounts borrowed under the bank financing facility discussed above). The revolving credit agreement also contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of March 31, 2009, the Company was in compliance with financial covenants contained in the revolving credit agreement.

On November 1, 2008, Northern Utilities entered into a gas storage management agreement (the "Agreement") pursuant to which (i) Northern Utilities released certain pipeline and storage capacity to an asset manager from November 1, 2008 through April 30, 2009 and (ii) the asset manager financed inventories associated with the released storage capacity from Northern Utilities contemporaneously with the closing of the Acquisitions. The Agreement requires Northern Utilities to repurchase quantities of natural gas over the course of the 2008/2009 winter heating season at a specified price and any remaining balance of the gas inventory on April 30, 2009 at the same price initially paid by the asset manager. The Agreement provides for the Company to issue a guarantee of payment of $15 million for the term of the agreement. There is $5.0 million and $24.0 million outstanding at March 31, 2009 and December 31, 2008, respectively, related to this Agreement.

Guarantees

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2009 there are $27.1 million of guarantees outstanding and the longest of these guarantees extends through December 31, 2010. Of this amount, $8.1 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage Agreement discussed above. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of March 31, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.6 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite State notes due 2018. As of March 31, 2009, the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. This guarantee will terminate if Granite State reorganizes and merges with and into Northern Utilities.

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three months ended March 31, 2009 and March 31, 2008:

Three Months Ended March 31, 2009 (Millions)	Electric	Gas	Other	Non-Regulated	Total
Revenues	$ 62.1	$ 72.4	$ ---	$ 1.1	$ 135.6
Segment Profit	1.5	7.6	(0.4)	0.4	9.1
Identifiable Segment Assets	353.5	351.0	20.5	1.1	726.1
Capital Expenditures	13.3	4.6	0.1	---	18.0

Three Months Ended March 31, 2008 (Millions)					
Revenues	$ 56.6	$ 14.3	$ ---	$ 1.0	$ 71.9
Segment Profit (Loss)	0.5	2.8	(0.1)	0.1	3.3
Identifiable Segment Assets	331.2	111.5	26.9	1.0	470.6
Capital Expenditures	4.2	0.3	---	---	4.5

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2008 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 18, 2009.

Legal Proceedings

A putative class action Complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009 an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. The Company believes the suit is without merit, and will defend itself vigorously.

Regulatory Matters

Unitil Energy – On March 12, 2009, Unitil Energy, with the agreement of Staff of the NHPUC, filed a letter with the NHPUC seeking approval of a change in the date of its annual stranded cost recovery and external delivery reconciliation and rate revision filing to allow for inclusion of updated transmission costs that are effective June of each year. Unitil Energy proposes that its annual filing be submitted no later than 45 days before its proposed effective date of August 1, 2009. This matter remains pending.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On January 16, 2009, the NHPUC issued its decision in this matter, concluding that such rate mechanisms should only be implemented on a company-by-company basis in the context of an examination of company specific costs and revenues, service territory, customer mix and rate base investment. On March 23, 2009, the NHPUC denied a Motion for Rehearing of this matter.

Major Ice Storm – On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities.

An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Unitil was able to restore power to one-third of its Massachusetts customers within three days, 80 percent of its customers by day seven, and the final Massachusetts customers, including those with individual service problems, were restored by day 13, December 24, 2008. On January 7, 2009, the MDPU opened an investigation into the Preparation and Response of the Massachusetts electric distribution companies to the December 12, 2008 Winter Storm. On February 23, 2009, each electric distribution company, including Fitchburg, filed a report detailing its response to the storm and outages, and its service restoration efforts with the MDPU. On March 25, 2009, Fitchburg filed with the MDPU a second report, consisting of a self assessment of the Company's response to the storm, and a set of specific recommendations to improve its ability to respond to such emergencies in the future. Public hearings have been held in each of the electric distribution utilities' service territories in Massachusetts. Evidentiary hearings before the MDPU concerning Fitchburg's storm response are scheduled for mid-May, 2009. Based on its preliminary assessment, the Company has accrued and deferred, excluding capital construction expenditures, approximately $10 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. This matter remains pending.

Fitchburg – Gas Operations – On March 12, 2009, the MDPU opened an investigation into Fitchburg's gas procurement practices. The purpose of this investigation is to determine: (1) whether Fitchburg has engaged in a purchasing program to mitigate the volatility of gas commodity prices without MDPU approval; and, if so, (2) an appropriate remedy, including whether Fitchburg's ratepayers are entitled to reimbursement for any gas supply costs that are higher than they would have been absent such purchasing program. The Company believes that its gas procurement practices have been and remain in compliance and consistent with all relevant MDPU rules and orders and Massachusetts law, and does not believe that the investigation will have a material adverse impact upon the Company's financial condition or the results of its operations. This matter remains pending.

Fitchburg – Other – On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "The Green Communities Act" (the GC Act), an energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file a proposed plan to establish a smart grid pilot program. On March 31, 2009, pursuant to Section 85 of the GC Act, Fitchburg filed its Smart Grid Pilot Program with the MDPU. Fitchburg's proposal includes a power quality monitoring pilot, a distribution capacitor bank control pilot, and a residential time-of-use, critical peak period, and demand response pilot.

Northern Utilities – Notices of Probable Violation – Beginning in October 2007, the MPUC initiated formal investigations into a number of Notices of Probable Violation (NOPVs) alleging that Northern Utilities had violated various provisions of the federal pipeline safety regulations, as adopted by the MPUC. Northern Utilities, the MPUC Staff and Unitil filed a comprehensive settlement (Settlement), which was approved by the MPUC on November 21, 2008, resolving these matters. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for certain safety related improvements for which no rate recovery will be allowed and obligations to be undertaken for Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at March 31, 2009 was $2.3 million.

Northern Utilities – New Hampshire 2007/2008 Winter Cost of Gas – On October 31, 2007, the NHPUC issued Order No. 24,798 concerning the 2007/2008 winter cost of gas proceeding for Northern Utilities' New Hampshire division. In that order, the NHPUC noted that Northern Utilities had identified an unusually high level of lost and unaccounted for gas (UAFG), and ordered Northern Utilities to file a detailed report concerning its investigation of this matter. Through its investigation, Northern Utilities determined that the UAFG affected both its New Hampshire and Maine divisions, and that the cause appeared to be incorrect metering at the Maritimes & Northeast (M&NE) / Portland Natural Gas Transmission System's (PNGTS) Newington Gate Station caused by an erroneous meter module change. The metering equipment was operated and maintained by a third party, Spectra Energy, the parent company of M&NE. PNGTS and M&NE share joint ownership of the section of the pipeline connected to Granite State at the Newington Gate Station. The error caused Granite State to be billed for 758,702 Dth of natural gas, with Granite State then billing Northern Utilities for an equivalent amount, although the volumes of gas were not actually consumed. The meter error was corrected and Northern Utilities, Granite State, Spectra Energy and PNGTS reached an agreement whereby PNGTS will provide to Northern Utilities, through Granite State, gas volumes equal to the misread amounts to correct for the error, over a period of approximately 18 months. Both the NHPUC and the MPUC have approved this arrangement, as well as Northern Utilities' methodology for allocating the gas received to its Maine and New Hampshire divisions based upon the actual gas use over the period the meters were misread. As of March 31, 2009, Northern Utilities has recorded approximately $3.0 million reflecting the anticipated liability of the future refund amount based on current market prices with an offsetting receivable from Granite State.

Northern Utilities – Maine Capacity Costs – In its October 28, 2008 approval of Northern Utilities' Maine Division's Cost of Gas Factor for the 2008-2009 Winter Period, the MPUC approved recovery of an additional $0.5 million of annual demand costs that had been inadvertently omitted from Northern Utilities' reconciliation of the 2008-2009 Winter Period rates, although analogous costs had been included in its calculation of 2007-2008 Winter Period rates. The MPUC determined that recovery of these Local Production Capacity Costs was consistent with previous MPUC orders.

Northern Utilities also reported that, upon investigation, these annual demand costs, though approved, were incorrectly excluded from its reconciliation for five previous annual periods. The total impact for the five years is $2.4 million. On November 7, 2008, Northern Utilities filed a request with the MPUC seeking an accounting order allowing it to defer and amortize for recovery these unrecovered gas costs over a three year period. This matter remains pending.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2008 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 18, 2009.

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of March 31, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at March 31, 2009 are current and non-current accrued liabilities totaling $10.8 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties. Also included on the Company's Consolidated Balance Sheet at March 31, 2009 are current and non-current accrued liabilities totaling $2.4 million associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the recovery of these environmental remediation costs is probable through the regulatory process.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) – The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) – The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

Effective with the acquisitions of Northern Utilities and Granite State, the Company assumed the assets and obligations of the Northern Utilities and Granite State pension plans with respect to active union employees. All other active employees of Northern Utilities and Granite State effectively became members of the Company's Pension Plan as of the acquisitions closing date.

Certain employees of Northern Utilities qualified for participation in the Company's PBOP Plan effective with the acquisition closing date.

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

	2009	2008
Used to Determine Plan Costs		
Discount Rate	**6.25%**	**6.00%**
Rate of Compensation Increase	**3.50%**	**3.50%**
Expected Long-term rate of return on plan assets	**8.50%**	**8.50%**
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	**8.50%**
Ultimate Health Care Cost Trend Rate	**4.00%**	**4.00%**
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	**2017**
Used to Determine Benefit Obligations:		
Discount Rate	**6.25%**	**6.00%**
Rate of Compensation Increase	**3.50%**	**3.50%**
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	**8.50%**
Ultimate Health Care Cost Trend Rate	**4.00%**	**4.00%**
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	**2017**

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan		PBOP Plan		SERP	
Three Months Ended March 31,	**2009**	2008	**2009**	2008	**2009**	2008
Service Cost	**$ 571**	**$ 488**	**$ 357**	**$ 355**	**$ 54**	**$ 37**
Interest Cost	**1,073**	**944**	**578**	**559**	**45**	**32**
Expected Return on Plan Assets	**(1,108)**	**(1,093)**	**(89)**	**(81)**	**---**	**---**
Prior Service Cost Amortization	**66**	**27**	**428**	**340**	**---**	**---**
Transition Obligation Amortization	**---**	**---**	**5**	**5**	**---**	**---**
Actuarial Loss Amortization	**399**	**319**	**---**	**---**	**18**	**6**
Sub-total	**1,001**	**685**	**1,279**	**1,178**	**117**	**75**
Amounts Capitalized and Deferred	**(282)**	**(201)**	**(358)**	**(439)**	**---**	**---**
Net Periodic Benefit Cost Recognized	**$ 719**	**$ 484**	**$ 921**	**$ 739**	**$ 117**	**$ 75**

Employer Contributions

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 - 2010 plan years. This did not affect the Company's Pension Plan in 2008 as its Pension Plan was 99% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2008 and met the exemption from the shortfall amortization. The Company expects to contribute approximately $4.0 million to fund its Pension Plan in 2009.

As of March 31, 2009, the Company had made $0.2 million and $13,000 of contributions to the PBOP and SERP Plans, respectively, in 2009. The Company presently anticipates contributing an additional $2.6 million and $40,000 to the PBOP and SERP Plans, respectively, in 2009.

NOTE 9: INCOME TAXES

The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2008 and for the current interim reporting period ended March 31, 2009 in accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2005; December 31, 2006; and December 31, 2007. Income tax filings for the year ended December 31, 2008 have been extended until September 15, 2009. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

NOTE 10: UNAUDITED PRO FORMA FINANCIAL DATA RELATED TO ACQUISITIONS

On December 1, 2008, the Company acquired Northern Utilities and Granite State, as discussed in Note 1. Had the results of operations for Northern Utilities and Granite State been combined with the Company as of the beginning of 2008, the Company's pro forma results for the three months ended March 31, 2008 would have been as follows:

(Millions, except per share amounts) (Unaudited)	Three Months Ended March 31, 2008
Revenues	$ 126.4
Earnings Applicable to Common Shareholders	$ 7.0
Earnings per Share	
Basic	$ 0.88
Diluted	$ 0.88

The Unaudited Pro Forma Financial Data are presented for illustrative purposes only and do not indicate the financial results of the combined companies had the companies actually been combined and had the impact of possible revenue enhancements and expense efficiencies, among other factors, been considered, and is not intended to be a projection of future results.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in the Company's internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2008 as filed with the SEC on February 18, 2009.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended March 31, 2009.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 26, 2008, the Company periodically repurchased shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. There was no pool or maximum number of shares related to these purchases; however, the trading plan automatically terminated when $82,500 in value of shares were purchased so that, as of March 31, 2009, the value of shares that may yet be purchased under the trading plan was $0.

The Company adopted a new written trading plan under Rule 10b5-1 under the Exchange Act on March 26, 2009, covering the period March 26, 2009 through March 26, 2010. The Company may suspend or terminate this trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases; however, the trading plan will terminate when $83,000 in value of shares have been purchased or, if sooner, on March 26, 2010.

The Company's repurchases are shown in the table below for the monthly periods noted:

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
1/1/09 – 1/31/09	---	---	---
2/1/09 – 2/28/09	---	---	---
3/1/09 – 3/31/09	214	$18.61	214
Total	214	$18.61	214

Item 5. Other Information

On April 27, 2009, the Company issued a press release announcing its results of operations for the three-month period ended March 31, 2009. The press release is furnished with the Quarterly Report on Form 10-Q as Exhibit 99.1.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated April 27, 2009 Announcing Earnings For the Quarter Ended March 31, 2009.	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: April 28, 2009

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: April 28, 2009

/s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated April 27, 2009 Announcing Earnings For the Quarter Ended March 31, 2009.	Filed herewith

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING

(Millions, except for per share data)

(UNAUDITED)

	Three Months Ended March 31,	
	2009	2008
Net Income	**$9.1**	$3.3
Less: Dividend Requirements on Preferred Stock	**---**	---
Net Income Applicable to Common Stock	**$9.1**	$3.3
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**8,018**	5,719
Dilutive Effect of Stock Options and Restricted Stock (000's)	**---**	5
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**8,018**	5,724
Earnings Per Share – Basic	**$1.14**	$0.57
Earnings Per Share – Diluted	**$1.14**	$0.57

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2009

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2009

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2009

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending March 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	April 28, 2009
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	April 28, 2009
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	April 28, 2009

For Immediate Release

Exhibit 99.1

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports First Quarter Earnings

Hampton, NH – April 27, 2009: Unitil Corporation (NYSE: UTL) (www.unitil.com) today announced Earnings Applicable to Common Shareholders of $9.1 million for the first quarter of 2009, an increase of $5.8 million over 2008 first quarter earnings of $3.3 million. Earnings per common share (EPS) were $1.14 for the three months ended March 31, 2009, an improvement of $0.57 per share over the first quarter of 2008. Earnings in the first quarter of 2009 reflect the acquisition, on December 1, 2008, of Northern Utilities, Inc. (Northern Utilities) and Granite State Gas Transmission, Inc. (Granite State).

"Our strong financial results in the first quarter of 2009 reflect the strategic acquisition we completed in December of 2008," said Robert G. Schoenberger, Unitil's Chairman and Chief Executive Officer. "Unitil is now a larger company with a more diverse portfolio of local natural gas and electric distribution utility operations, which positions us well in a challenging economic environment."

Natural gas sales margin increased $18.1 million in the three months ended March 31, 2009 compared to the same period in 2008. This increase primarily reflects the contribution to natural gas sales margin by Northern Utilities, the Company's recently acquired local gas distribution utility. In addition to the contribution by Northern Utilities, total therm sales of natural gas increased 6.0% in the three months ended March 31, 2009 compared to the same period in 2008, reflecting increases of 6.3% and 5.9% in sales to residential and commercial and industrial (C&I) customers, respectively. The higher sales in the first three months of 2009 reflect a colder winter heating season this year and increased usage of natural gas by C&I customers for production operations. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

Electric sales margin increased $1.3 million in the three months ended March 31, 2009 compared to the same period in 2008, reflecting higher electric base rates in the current quarter, partially offset by lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 4.7% in the three months ended March 31, 2009 compared to the same period in 2008 driven by lower average usage per customer reflecting the continued economic slowdown and energy conservation.

Selected financial data for 2009 is presented in the following table:

Unitil Corporation - Condensed Financial Data

	(Millions, except Per Share Data) (Unaudited)		
	Three Months Ended March 31,		
	2009	**2008**	**Change**
Gas Therm Sales: (a)			
Residential	19.3	4.8	302.1%
Commercial/Industrial	58.1	6.8	754.4%
Total Gas Therm Sales	**77.4**	**11.6**	**567.2%**
Electric kWh Sales:			
Residential	180.6	182.4	(1.0%)
Commercial/Industrial	242.1	261.1	(7.3%)
Total Electric kWh Sales	**422.7**	**443.5**	**(4.7%)**

(a) 2009 Gas Therm Sales include Northern Utilities, Inc., acquired on December 1, 2008.

	2009	2008	Change
Gas Revenues	**$ 72.4**	**$ 14.3**	**$ 58.1**
Purchased Gas	49.0	9.0	40.0
Gas Sales Margin	**23.4**	**5.3**	**18.1**
Electric Revenues	**62.1**	**56.6**	**5.5**
Purchased Electricity	47.7	43.5	4.2
Electric Sales Margin	**14.4**	**13.1**	**1.3**
Usource™ Sales Margin	**1.1**	**1.0**	**0.1**
Total Sales Margin	**38.9**	**19.4**	**19.5**
Operation & Maintenance	10.4	4.7	5.7
Depreciation, Amortization, Taxes & Other	14.6	8.8	5.8
Interest Expense, Net	4.8	2.6	2.2
Earnings Applicable to Common Shareholders	**$ 9.1**	**$ 3.3**	**$ 5.8**
Earnings Per Share	**$ 1.14**	**$ 0.57**	$ **0.57**

Total Operation & Maintenance (O&M) expenses increased $5.7 million in the three months ended March 31, 2009 compared to the same period in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $2.1 million of the increase. In addition, higher year over year compensation and employee benefit expenses of $0.7 million and higher utility operating costs of $0.4 million, partially offset by lower professional fees of $0.3 million, contributed to the increase in O&M expenses. The increase in O&M expenses also reflects higher insurance costs in 2009 compared to 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Depreciation, Amortization, Taxes and Other expenses increased $5.8 million in the three months ended March 31, 2009 compared to the same period in 2008. The increase primarily reflects the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs.

Interest Expense, Net increased $2.2 million in the three months ended March 31, 2009 compared to the same period in 2008. The addition of Northern Utilities and Granite State accounted for $1.7 million of the increase, reflecting the issuance of long-term notes by Northern Utilities and Granite State in December 2008. In addition, the increase in Interest Expense, Net reflects higher average borrowings in the current quarter.

Also in the first quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

In December 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering. In January 2009, the underwriters exercised the over-allotment option associated with this offering and purchased an additional 270,000 shares of the Company's common stock. The Company used net proceeds of $41.9 million from these issuances to repay a portion of the bank financing for the Company's acquisitions of Northern Utilities and Granite State and to repay other short-term indebtedness. Overall, the positive results of operations and net income are reflected over a higher number of average shares outstanding year over year.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

About Unitil

Unitil is a public utility holding company with subsidiaries providing electric and natural gas distribution service in New Hampshire and Massachusetts, natural gas distribution service in Maine and energy services throughout the northeast. Unitil serves approximately 170,000 utility customers in three states. Its utility affiliates include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc. and Granite State Gas Transmission, Inc. Its other subsidiaries include Unitil Service Corp. and its non-regulated business segment doing business as Usource.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended June 30, 2009

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	**(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 23, 2009
Common Stock, No par value	**10,816,882 Shares**

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended June 30, 2009

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the Federal Energy Regulatory Commission (the "FERC") under the Energy Policy Act of 2005.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly owned distribution utilities: (i) Unitil Energy Systems, Inc. (Unitil Energy), which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the city of Concord, New Hampshire; (ii) Fitchburg Gas and Electric Light Company (Fitchburg), which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and (iii) Northern Utilities, Inc. (Northern Utilities), which provides natural gas service in southeastern New Hampshire, including the city of Portsmouth, and portions of southern and central Maine, including the city of Portland. In addition, Unitil is the parent company of Granite State Gas Transmission, Inc. (Granite State), an interstate natural gas transmission pipeline company that principally provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory.

The Company's distribution utilities serve approximately 100,300 electric customers and 69,300 natural gas customers in their service territory. The Company's distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in Net Utility Plant of $426.8 million at June 30, 2009. The Company does not own or operate electric generating facilities or major transmission facilities and substantially all of the Company's utility assets are dedicated to the local delivery of electricity and natural gas to its customers. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

On December 1, 2008, Unitil purchased (i) all of the outstanding capital stock of Northern Utilities from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State and Unitil (the "Acquisitions"). Bay State is a wholly owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt.

A fifth wholly owned subsidiary, Unitil Power Corp. (Unitil Power), formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

The Company also has three other wholly owned subsidiaries: Unitil Service Corp. (Unitil Service); Unitil Realty Corp. (Unitil Realty); and Unitil Resources, Inc. (Unitil Resources). Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, "Usource") are indirect subsidiaries that are wholly owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Table of Contents

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, in regards to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and the Maine Public Utilities Commission (MPUC). Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party suppliers. A majority of Unitil's largest commercial and industrial (C&I) customers purchase their electric and natural gas supplies from third party suppliers. However, most residential and small customers continue to purchase their electric and natural gas supplies through Unitil's distribution utilities. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features. For additional discussion, please refer to Unitil's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 18, 2009.

CAUTIONARY STATEMENT

This report and the documents the Company incorporates by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's and its management's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Part II, Item 1A (Risk Factors) and the following:

- The Company's ability to integrate the business, operations and personnel of Northern Utilities and Granite State and to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;

Table of Contents

- General economic conditions, including recent distress in the financial markets that has had an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of the Company's counterparty obligations, including those of Unitil's insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended June 30, 2009 and June 30, 2008 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Part I, Item 1 of this report.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in current and future reporting periods will reflect to a greater degree the seasonal nature of the natural gas business. Specifically, the Company expects consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of current and future reporting years.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders was $0.2 million for the second quarter of 2009, compared to earnings of $1.6 million for the second quarter of 2008. Earnings per common share (EPS) were $0.03 for the three months ended June 30, 2009 compared with $0.28 in the second quarter of 2008. For the six months ended June 30, EPS were $1.10 for 2009 compared to $0.85 for 2008, an increase of $0.25 per share, or 29%, reflecting the positive impact from the acquisitions of Northern Utilities and Granite State.

Earnings for the second quarter of 2009 reflect the greater degree to which the seasonal nature of the natural gas business now affects the Company's earnings as a result of the acquisitions of Northern Utilities and Granite State, as discussed above. Earnings in the second quarter reflect higher gas utility sales margins offset by lower electric utility sales margins and higher operating, depreciation and interest costs in the quarter as well as a higher number of average shares outstanding year over year, discussed below.

Natural gas sales margin increased $8.4 million and $26.5 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the contribution by Northern Utilities, the Company's recently acquired local gas distribution utility. Natural gas sales in the six month period ended June 30, 2009 reflect a colder winter heating season this year. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

Electric sales margin decreased $1.6 million and $0.3 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008, reflecting lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 6.8% and 5.7% in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008 due to lower average usage by our customers reflecting the continued regional economic slowdown.

Total Operation & Maintenance (O&M) expenses increased $5.0 million and $10.7 million for the three and six months ended June 30, 2009, respectively, compared to the same period in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $4.3 million of the increase in the six month period. For the six month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees expense of $1.9 million, primarily related to the December ice storm discussed below, higher compensation and employee benefit expenses of $0.6 million and higher utility operating costs of $1.1 million contributed to the increase in O&M expenses. The increase in O&M expenses for the six month period also reflects higher insurance costs in 2009 compared to the same period in 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Depreciation, Amortization, Taxes and Other expenses increased $2.1 million and $7.9 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008. The increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs.

Interest Expense, Net increased $1.4 million and $3.6 million in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. These increases are primarily due to the addition of Northern Utilities and Granite State, reflecting the issuance of long-term notes by Northern Utilities and Granite State in December 2008. In addition, these increases in Interest Expense, Net reflect higher average borrowings in the current periods.

Usource, our non-regulated energy brokering business, recorded revenues of $1.1 million and $2.2 million in the three and six month periods ended June 30, 2009, respectively, increases of $0.3 million and $0.4 million over the comparable periods of 2008. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

On December 11 and 12, 2008, a severe ice storm struck the New England region, creating extended power outages for many residents of Massachusetts and New Hampshire, including Unitil's electric customers in New Hampshire and the greater Fitchburg, Massachusetts service territory. Based on its preliminary assessment, the Company has accrued and deferred, excluding capital construction expenditures, approximately $12.5 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations.

Between December 2008 and June 2009, the Company issued and sold 4,970,000 shares of its common stock, including its underwriters' excercise of overallotment options to purchase an additional 570,000 shares, at a price of $20.00 per share in registered public offerings. The Company used net proceeds of $93.1 million from these offerings (i) to repay all amounts outstanding under the bridge credit facility that the Company used to partially finance the acquisition of Northern Utilities and Granite State which closed on December 1, 2008, and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt. See Note 4. Overall, the positive results of operations and net income are reflected over a higher number of average shares outstanding year over year.

In 2008, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2009, March, 2009 and June, 2009 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three and six months ended June 30, 2009 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

The Company's Total Assets increased by $230.9 million as of June 30, 2009 compared to June 30, 2008. The increase in Total Assets was primarily due to the inclusion of the acquisitions of Northern Utilities and Granite State and to capital expenditures related to Unitil Energy's and Fitchburg's electric and gas distribution systems.

Table of Contents

The Company's Total Capitalization increased by $185.6 million as of June 30, 2009 compared to June 30, 2008 reflecting the issuance of common shares by the Company as part of its financing of the acquisitions of Northern Utilities and Granite State (See Note 4 to the accompanying Consolidated Financial Statements) and the issuance and sale of Senior Unsecured Notes by Northern Utilities and Granite State (See Note 5 to the accompanying Consolidated Financial Statements). The Company's Total Liabilities increased $45.3 million primarily due to the acquisitions of Northern Utilities and Granite State.

Gas Sales, Revenues and Margin

Therm Sales – Overall, Unitil's total therm sales of natural gas increased in the three and six month periods ended June 30, 2009 compared to the same periods in 2008. These increases primarily reflect the contribution of sales by Northern Utilities. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas decreased 9.7% in the three months ended June 30, 2009 compared to the same period in 2008 and increased 1.1% in the six months ended June 30, 2009 compared to the same period in 2008. The increase in the six month period ended June 30, 2009 reflects a colder winter heating season this year. Average winter temperatures in the Company's service territories were 6.4% colder than last year. The lower sales in the three month period ended June 30, 2009 reflect energy conservation and lower usage of natural gas by C&I customers for production operations.

The following table details total firm therm sales for the three and six months ended June 30, 2009 and 2008, by major customer class:

Therm Sales (millions) (a)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	% Change	2009	2008	Change	% Change
Residential	**6.9**	2.1	4.8	228.6%	**26.2**	6.9	19.3	279.7%
Commercial / Industrial	**28.5**	4.1	24.4	595.1%	**86.6**	10.9	75.7	694.5%
Total	**35.4**	6.2	29.2	471.0%	**112.8**	17.8	95.0	533.7%

(a) 2009 Therm Sales include Northern Utilities, acquired on December 1, 2008.

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and six months ended June 30, 2009 and 2008:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	$ Change	% Change(1)	2009	2008	$ Change	% Change(1)
Gas Operating Revenue:								
Residential	**$ 9.6**	$ 3.5	$ 6.1	92.4%	**$ 40.0**	$ 11.6	$ 28.4	135.9%
Commercial / Industrial	**13.8**	3.1	10.7	162.1%	**55.8**	9.3	46.5	222.5%
Total Gas Operating Revenue	**$ 23.4**	$ 6.6	$ 16.8	254.5%	**$ 95.8**	$ 20.9	$ 74.9	358.4%
Cost of Gas Sales:								
Purchased Gas	**$ 11.8**	$ 3.9	$ 7.9	119.7%	**$ 60.2**	$ 12.9	$ 47.3	226.3%
Conservation & Load Management	**0.6**	0.1	0.5	7.6%	**1.2**	0.1	1.1	5.3%
Gas Sales Margin	**$ 11.0**	$ 2.6	$ 8.4	127.3%	**$ 34.4**	$ 7.9	$ 26.5	126.8%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $16.8 million and $74.9 million in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the natural gas sales for Northern Utilities. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and Conservation & Load Management (C&LM) in Operating Expenses. The increase in Total Gas Operating Revenues in the second quarter of 2009 reflects higher Purchased Gas costs of $7.9 million, higher C&LM revenues of $0.5 million and higher gas sales margin of $8.4 million. The increase in Total Gas Operating Revenues in the first six months of 2009 reflects higher Purchased Gas costs of $47.3 million, higher C&LM revenues of $1.1 million and higher gas sales margin of $26.5 million.

The Purchased Gas and C&LM component of Gas Operating Revenues increased $8.4 million and $48.4 million in the three and six month periods ended June 30, 2009 compared to the same periods in 2008. These increases primarily reflect the natural gas sales for Northern Utilities. Purchased Gas revenues include the recovery of the cost of gas supply as well as other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $8.4 million and $26.5 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the contribution by Northern Utilities.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Unitil's total electric kilowatt (kWh) sales decreased 6.8% and 5.7% in the three and six month periods ended June 30, 2009, respectively compared to the same periods in 2008. Electric kWh sales to residential customers in the three and six month periods ended June 30, 2009 decreased 4.3% and 2.5%, respectively, compared to the same periods in 2008 while sales to C&I customers decreased 8.2% and 7.7%, respectively, in those periods compared to the same periods in 2008. The lower kWh sales in 2009 compared to 2008 reflect lower average usage by our customers due to the continued regional economic slowdown.

The following table details total kWh sales for the three and six months ended June 30, 2009 and 2008 by major customer class:

kWh Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	% Change	2009	2008	Change	% Change
Residential	**141.1**	147.5	(6.4)	(4.3%)	**321.7**	329.9	(8.2)	(2.5%)
Commercial / Industrial	**233.2**	254.0	(20.8)	(8.2%)	**475.3**	515.1	(39.8)	(7.7%)
Total	**374.3**	401.5	(27.2)	(6.8%)	**797.0**	845.0	(48.0)	(5.7%)

[Table of Contents](#)

Electric Operating Revenues and Sales Margin – The following table details total Electric Operating Revenues and Sales Margin for the three and six month periods ended June 30, 2009 and 2008:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	**2008**	**$ Change**	**% Change[1]**	**2009**	**2008**	**$ Change**	**% Change[1]**
Electric Operating Revenue:								
Residential	**$ 23.3**	$ 25.9	$ (2.6)	(5.0%)	**$ 56.4**	$ 56.2	$ 0.2	0.2%
Commercial / Industrial	**23.7**	26.1	(2.4)	(4.6%)	**52.7**	52.4	0.3	0.3%
Total Electric Operating Revenue	**$ 47.0**	$ 52.0	$ (5.0)	(9.6%)	**$ 109.1**	$ 108.6	$ 0.5	0.5%
Cost of Electric Sales:								
Purchased Electricity	**$ 33.4**	$ 36.8	$ (3.4)	(6.5%)	**$ 80.6**	$ 79.7	$ 0.9	0.9%
Conservation & Load Management	**0.8**	0.8	—	—	**1.3**	1.4	(0.1)	(0.1%)
Electric Sales Margin	**$ 12.8**	$ 14.4	$ (1.6)	(3.1%)	**$ 27.2**	$ 27.5	$ (0.3)	(0.3%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues, decreased by $5.0 million, or 9.6%, and increased by $0.5 million, or 0.5%, in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The decrease in Total Electric Operating Revenues in the second quarter of 2009 reflects lower Purchased Electricity costs of $3.4 million and lower electric sales margin of $1.6 million. The increase in Total Electric Operating Revenues in the first six months of 2009 reflects higher Purchased Electricity costs of $0.9 million, partially offset by lower C&LM revenues of $0.1 million and lower electric sales margin of $0.3 million.

The Purchased Electricity and C&LM component of Total Electric Operating Revenues decreased $3.4 million, or 6.5%, and increased a net $0.8 million, or 0.8%, in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. The decrease in the three month period reflects lower sales volumes and lower electric commodity prices. The increase in the six month period reflects higher electric commodity prices and a decrease in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by lower sales volumes and lower spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin decreased $1.6 million and $0.3 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008. The decrease in the three month period reflects lower sales volumes. The decrease in the six month period reflects lower sales volumes partially offset by higher electric base rates implemented in March 2008.

Table of Contents

Operating Revenue - Other

The following table details total Other Revenue for the three and six months ended June 30, 2009 and 2008:

Other Revenue (000's)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	$ Change	% Change	2009	2008	$ Change	% Change
Other	**$ 1.1**	$ 0.8	$ 0.3	37.5%	**$ 2.2**	$ 1.8	$ 0.4	22.2%
Total Other Revenue	**$ 1.1**	$ 0.8	$ 0.3	37.5%	**$ 2.2**	$ 1.8	$ 0.4	22.2%

Total Other Revenue increased $0.3 million, or 37.5% and $0.4 million, or 22.2%, in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $7.9 million and $47.3 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the natural gas supply purchases for Northern Utilities, which were not included in the prior year period. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity decreased $3.4 million, or 9.2%, and increased $0.9 million, or 1.1%, in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. The decrease in the three month period primarily reflects lower sales volumes and lower electric commodity prices. The increase in the six month period reflects higher electric commodity prices and a decrease in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by lower sales volumes. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expenses increased $5.0 million and $10.7 million for the three and six months ended June 30, 2009, respectively, compared to the same period in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $1.9 million and $4.3 million of the increases in the three and six month periods, respectively. For the three month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees of $2.2 million, primarily related to the internal review and legal and regulatory proceedings associated with the ice storm of December 2008, higher compensation and employee benefit expenses of $0.2 million, reflecting normal annual increases, and higher utility operating costs of $0.7 million contributed to the increase in O&M expenses. For the six month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees of $1.9 million, primarily related to the internal review and legal and regulatory proceedings associated with the ice storm of December 2008, higher compensation and employee benefit expenses of $0.6 million and higher utility operating costs of $1.1 million contributed to the increase in O&M expenses. The increase in the six month period also reflects higher insurance costs in 2009 compared to 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Conservation & Load Management – Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased $0.5 million, or 55.6% and $1.0 million, or 66.7%, in the three and six month periods ended June 30, 2009 compared to the same periods in 2008. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Depreciation, Amortization and Taxes

Depreciation and Amortization – Depreciation and Amortization expense increased $1.9 million, or 42.2% and $3.0 million, or 30.9% in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs.

Local Property and Other Taxes – Local Property and Other Taxes increased $0.8 million and $2.1 million in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher local property tax rates on higher levels of utility plant in service.

Federal and State Income Taxes – Federal and State Income Taxes were lower by $0.6 million in the three month period ended June 30, 2009 compared to the same period in 2008 reflecting lower pre-tax earnings. Federal and State Income Taxes were higher by $2.9 million in the six month period ended June 30, 2009 compared to the same period in 2008 reflecting higher pre-tax earnings.

Other Non-operating Expenses (Income)

Other Non-operating Expenses were flat in the three month period ended June 30, 2009 compared to the same period in 2008. For the six month period ended June 30, 2009, Other Non-operating Expenses decreased $0.1 million compared to the same period in 2008. This change reflects an adjustment of $0.1 million recorded in the first quarter of 2008 in conjunction with the Company's approved electric base distribution rate increase in Massachusetts.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

[Table of Contents](#)

Interest Expense, Net (Millions)	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	Change	2009	2008	Change
Interest Expense						
Long-term Debt	**$ 4.5**	$ 2.9	$ 1.6	**$ 9.1**	$ 5.7	$ 3.4
Short-term Debt	**0.6**	0.2	0.4	**1.1**	0.5	0.6
Regulatory Liabilities	**0.1**	—	0.1	**0.1**	0.1	—
Subtotal Interest Expense	**5.2**	3.1	2.1	**10.3**	6.3	4.0
Interest (Income)						
Regulatory Assets	**(0.6)**	(0.7)	0.1	**(1.3)**	(1.3)	—
AFUDC and Other	**(0.9)**	(0.1)	(0.8)	**(0.5)**	(0.1)	(0.4)
Subtotal Interest (Income)	**(1.5)**	(0.8)	(0.7)	**(1.8)**	(1.4)	(0.4)
Total Interest Expense, Net	**$ 3.7**	$ 2.3	$ 1.4	**$ 8.5**	$ 4.9	$ 3.6

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

Interest Expense, Net increased $1.4 million and $3.6 million in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2009. These increases were primarily due to the issuance of the long-term notes, noted above, and higher average borrowings in the current periods, partially offset by lower interest expense related to the repayment of the bank financing facility in the second quarter of 2009. In the second quarter of 2009, the permanent financing of the acquisition was completed and the associated interim financing fees and costs of the acquisition were recognized as part of transaction costs, to be amortized over 10 years, in accordance with the provisions of the regulatory orders approving the acquisitions by the NHPUC and MPUC.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

At June 30, 2009, the Company had $30.6 million in short-term debt outstanding through bank borrowings under its revolving credit agreement. The revolving credit agreement contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of June 30, 2009, the Company was in compliance with financial covenants contained in the revolving credit agreement.

During the second quarter of 2009, the Company repaid the remaining $39.1 million outstanding under a bank financing facility utilized in connection with the financing of the acquisition of Northern Utilities and Granite State on December 1, 2008.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of June 30, 2009, there were approximately $18.3 million of guarantees outstanding and these guarantees extend through December 31, 2010.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of June 30, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.5 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Cash Flows

On December 1, 2008, the Company acquired Northern Utilities and Granite State. Cash flow results for the first six months of 2009 include the activity for the acquired companies. Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for the six months ended June 30, 2009 compared to the same period in 2008.

	Six Months Ended June 30,	
	2009	**2008**
Cash Provided by Operating Activities	**$ 18.7**	$ 19.8

Cash Provided by Operating Activities – Cash Provided by Operating Activities was $18.7 million during the six months ended June 30, 2009, a decrease of $1.1 million over the comparable period in 2008. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes increased by $3.6 million as compared to 2008, and sources of cash for working capital increased $11.2 million, primarily related to the funding in 2009 of deferred regulatory charges related to the December ice storm, while all other sources and uses of cash from Operating Activities resulted in a net use of cash of $15.9 million in the first six months of 2009 compared to 2008.

	Six Months Ended June 30,	
	2009	**2008**
Cash (Used in) Investing Activities	**$ (26.1)**	$ (10.2)

Cash (Used in) Investing Activities – Cash (Used in) Investing Activities was $26.1 million for the six months ended June 30, 2009, an increase in capital spending of $15.9 million over the comparable period in 2008. Of this amount, $7.5 million is related to expenditures for the December 2008 ice storm, and $6.9 million is related to capital expenditures for Northern Utilities.

	Six Months Ended June 30,	
	2009	2008
Cash Provided by (Used in) Financing Activities	**$ 6.2**	$ (9.9)

Cash Provided by (Used in) Financing Activities – Cash Provided by Financing Activities was $6.2 million in the six months ended June 30, 2009. Proceeds from the issuance of Common Stock of $56.2 million primarily reflect the issuance of common stock by the Company through public offerings, as discussed above (See Note 4). Short-term borrowings were reduced by $43.5 million in the first six months of 2009 which included the repayment of the temporary bank credit facility utilized in financing the acquisition of Northern Utilities and Granite State on December 1, 2008. Uses of cash of $5.6 million primarily reflect Unitil's regular quarterly dividend payments on Common and Preferred Stock, and the scheduled repayment of long-term debt.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 18, 2009.

Regulatory Accounting – The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy is regulated by the FERC and the NHPUC. Fitchburg is regulated by the FERC and the MDPU. Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Table of Contents

Regulatory Assets consist of the following (millions)

	June 30, 2009	June 30, 2008	December 31, 2008
Energy Supply Contract Obligations	**$ 42.8**	$ 62.7	$ 52.7
Deferred Regulatory and Other Charges	**40.9**	28.8	28.3
Generation-related Assets	**0.4**	1.2	0.8
Subtotal – Restructuring Related Items	**84.1**	92.7	81.8
Retirement Benefit Obligations	**46.3**	35.2	45.5
Income Taxes	**15.3**	13.8	16.0
Environmental Obligations	**21.4**	11.3	19.7
Other	**10.2**	3.2	10.1
Total Regulatory Assets	**$ 177.3**	$ 156.2	$ 173.1
Less: Current Portion of Regulatory Assets[1]	**24.3**	22.4	26.9
Regulatory Assets - noncurrent	**$ 153.0**	$ 133.8	$ 146.2

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition – Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts – The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Table of Contents

Retirement Benefit Obligations – The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2008 and 2007, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2008 and 2007, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $675,000 and $690,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $531,000 and $539,000, respectively. (See Note 9 to the accompanying Consolidated Financial Statements).

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) and under FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109.

Depreciation – Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies – The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of June 30, 2009, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

As of June 30, 2009, 148 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two agreements expire on May 31, 2010, one agreement expires on June 5, 2010 and one agreement expires on March 31, 2012. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rates on the Company's short-term borrowings for the three months ended June 30, 2009 and June 30, 2008 were 4.28% and 2.84%, respectively. The average interest rates on the Company's short-term borrowings for the six months ended June 30, 2009 and June 30, 2008 were 4.53% and 3.40%, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 8 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Table of Contents

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Operating Revenues				
Gas	**$ 23.4**	$ 6.6	**$ 95.8**	$ 20.9
Electric	**47.0**	52.0	**109.1**	108.6
Other	**1.1**	0.8	**2.2**	1.8
Total Operating Revenues	**71.5**	59.4	**207.1**	131.3
Operating Expenses				
Purchased Gas	**11.8**	3.9	**60.2**	12.9
Purchased Electricity	**33.4**	36.8	**80.6**	79.7
Operation and Maintenance	**12.0**	7.0	**22.4**	11.7
Conservation & Load Management	**1.4**	0.9	**2.5**	1.5
Depreciation and Amortization	**6.4**	4.5	**12.7**	9.7
Provisions for Taxes:				
Local Property and Other	**2.2**	1.4	**5.2**	3.1
Federal and State Income	**0.1**	0.7	**5.4**	2.5
Total Operating Expenses	**67.3**	55.2	**189.0**	121.1
Operating Income	**4.2**	4.2	**18.1**	10.2
Non-Operating Expenses	**0.2**	0.2	**0.2**	0.3
Income Before Interest Expense	**4.0**	4.0	**17.9**	9.9
Interest Expense, Net	**3.7**	2.3	**8.5**	4.9
Net Income	**0.3**	1.7	**9.4**	5.0
Less: Dividends on Preferred Stock	**0.1**	0.1	**0.1**	0.1
Earnings Applicable to Common Shareholders	**$ 0.2**	$ 1.6	**$ 9.3**	$ 4.9
Average Common Shares Outstanding – Basic (000's)	**9,014**	5,736	**8,516**	5,728
Average Common Shares Outstanding—Diluted (000's)	**9,014**	5,741	**8,516**	5,733
Earnings Per Common Share (Basic and Diluted)	**$ 0.03**	$ 0.28	**$ 1.10**	$ 0.85
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.035**	$ 1.035

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) June 30, 2009	(UNAUDITED) June 30, 2008	December 31, 2008
ASSETS:			
Utility Plant:			
Electric	**$ 294.1**	$ 272.8	$ 289.0
Gas	**314.5**	69.8	304.2
Common	**27.8**	27.2	30.5
Construction Work in Progress	**13.4**	7.3	17.7
Total Utility Plant	**649.8**	377.1	641.4
Less: Accumulated Depreciation	**223.0**	126.0	218.6
Net Utility Plant	**426.8**	251.1	422.8
Current Assets:			
Cash	**10.3**	4.3	11.5
Accounts Receivable – Net of Allowance for Doubtful Accounts of $2.8, $1.3 and $3.0	**30.9**	22.5	39.7
Accrued Revenue	**31.0**	36.6	56.9
Gas Inventory	**8.5**	2.0	31.6
Materials and Supplies	**3.0**	1.9	2.7
Prepayments and Other	**4.1**	2.2	5.9
Total Current Assets	**87.8**	69.5	148.3
Noncurrent Assets:			
Regulatory Assets	**153.0**	133.8	146.2
Other Noncurrent Assets	**26.9**	9.2	15.9
Total Noncurrent Assets	**179.9**	143.0	162.1
TOTAL	**$ 694.5**	$ 463.6	$ 733.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) June 30, 2009	(UNAUDITED) June 30, 2008	December 31, 2008
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 195.9**	$ 100.0	$ 139.5
Preferred Stock	**2.0**	2.0	2.0
Long-Term Debt, Less Current Portion	**249.1**	159.4	249.3
Total Capitalization	**447.0**	261.4	390.8
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.4	0.4
Accounts Payable	**19.1**	18.2	36.3
Short-Term Debt	**30.6**	12.8	74.1
Energy Supply Contract Obligations	**18.1**	19.9	42.0
Other Current Liabilities	**32.9**	8.8	33.8
Total Current Liabilities	**101.1**	60.1	186.6
Deferred Income Taxes	**29.8**	34.2	31.1
Noncurrent Liabilities:			
Energy Supply Contract Obligations	**27.7**	42.8	34.6
Retirement Benefit Obligations	**71.1**	51.0	67.4
Environmental Obligations	**11.4**	12.0	12.3
Other Noncurrent Liabilities	**6.4**	2.1	10.4
Total Noncurrent Liabilities	**116.6**	107.9	124.7
TOTAL	**$ 694.5**	$ 463.6	$ 733.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Six Months Ended June 30,	
	2009	**2008**
Operating Activities:		
Net Income	**$ 9.4**	$ 5.0
Adjustments to Reconcile Net Income to Cash		
Provided by Operating Activities:		
Depreciation and Amortization	**12.7**	9.7
Deferred Taxes	**(2.6)**	1.2
Changes in Current Assets and Liabilities:		
Accounts Receivable	**8.8**	2.4
Accrued Revenue	**25.9**	(1.5)
Accounts Payable	**(17.2)**	0.6
All other Current Assets and Liabilities	**(4.0)**	0.8
Deferred Regulatory and Other Charges	**(12.2)**	1.7
Other, net	**(2.1)**	(0.1)
Cash Provided by Operating Activities	**18.7**	19.8
Investing Activities:		
Property, Plant and Equipment Additions	**(26.1)**	(10.2)
Cash (Used in) Investing Activities	**(26.1)**	(10.2)
Financing Activities:		
Proceeds From (Repayment of) Short-Term Debt, net	**(43.5)**	(6.0)
Dividends Paid	**(5.6)**	(4.0)
Proceeds from Issuance of Common Stock, net	**56.2**	0.5
Other, net	**(0.9)**	(0.4)
Cash Provided by (Used in) Financing Activities	**6.2**	(9.9)
Net (Decrease) in Cash	**(1.2)**	(0.3)
Cash at Beginning of Period	**11.5**	4.6
Cash at End of Period	**$ 10.3**	$ 4.3
Supplemental Cash Flow Information:		
Interest Paid	**$ 9.7**	$ 6.1
Income Taxes Paid	**$ 0.5**	$ 0.5

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase Agreement (SPA) dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the "Acquisitions").

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern and central Maine and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the distribution utilities).

Granite State is a natural gas transportation pipeline, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third -party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service; Unitil Realty; and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and six months ended June 30, 2009 are not necessarily indicative of results to be expected for the year ending December 31, 2009. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2008, as filed with the Securities and Exchange Commission (SEC) on February 18, 2008, for a description of the Company's Basis of Presentation.

As discussed above, the Company acquired Northern Utilities and Granite State on December 1, 2008. Accordingly, the operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from the date of acquisition, including the three and six months ended June 30, 2009 but not for the three and six months ended June 30, 2008. See Note 11.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Derivatives – The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases NYMEX futures that correspond to the associated delivery month. Any gains or losses on the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. As a result of the ratemaking process, the Company records gains and losses as regulatory liabilities or assets and recognizes such gains or losses in Purchased Gas when recovered in revenues. The Company's Consolidated Balance Sheets include derivative liabilities related to net unrealized losses on futures contracts in Other Current Liabilities and Noncurrent Liabilities which are offset in Accrued Revenues on the Company's Consolidated Balance Sheets.

Reclassifications – Based on the Company's analysis certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation, principally including the reclassification of $23.0 million of Noncurrent Assets to Current Assets and $19.9 million of Noncurrent Liabilities to Current Liabilities related to current collections and obligations of Regulatory Assets and Regulatory Liabilities for 2008.

Recently Issued Pronouncements – In May 2009, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 165, "Subsequent Events", (SFAS No. 165), effective for interim and annual reporting periods ending after June 15, 2009. SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company adopted SFAS No. 165 and it did not have an impact on the Company's Consolidated Financial Statements. The Company evaluated all events or transactions that occurred after June 30, 2009 up through July 23, 2009. During this period no material subsequent events came to our attention.

On April 9, 2009, the FASB issued FASB Staff Position No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments" (FSP FAS 107-1). FSP FAS 107-1 amends FASB Statement No. 107, "Disclosures about Fair Value of Financial Instruments" to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. FSG FAS 107-1 also amends Accounting Principles Board Opinion No. 28, "Interim Financial Reporting", to require those disclosures in summarized financial information at interim reporting periods. FSP FAS 107-1 is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company has adopted FSP FAS 107-1 and there was no impact on the Company's Consolidated Financial Statements. See Note 5 for relevant disclosures on the fair value of the Company's long-term debt.

On December 30, 2008, the FASB issued FASB Staff Position No. FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets", (FSP FAS 132(R)-1) to provide guidance on an employers' disclosures about plan assets of a defined benefit pension or other postretirement plan. The disclosures about plan assets required by FSP FAS 132(R)-1 are to be provided for fiscal years ending after December 15, 2009. The Company does not expect that the adoption of FSP FAS 132(R)-1 will have an impact on the Company's Consolidated Financial Statements.

NOTE 2 – ACQUISITIONS

As discussed above, on December 1, 2008, the Company purchased (i) all of the outstanding capital stock of Northern Utilities from Bay State and (ii) all of the outstanding capital stock of Granite State from NiSource pursuant to the SPA dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil. The aggregate purchase price for the Acquisitions was $209.2 million, comprised of $160 million in cash, plus an additional working capital adjustment of $49.2 million. The largest component of working capital was approximately $30.0 million of natural gas storage inventory.

The Company accounted for the Acquisitions under the purchase method of accounting for business combinations, in accordance with FASB Statement No. 141, "Business Combinations" ("SFAS No. 141") and SFAS No. 71. Accordingly, the Company recognized its estimate of the bargain purchase price (see "Plant Acquisition Adjustment" in the table below) at December 1, 2008. The process of valuing the assets, liabilities and transaction, transition and financing costs as a result of the Acquisitions was substantially completed in the second quarter of 2009. As a result, the Company has recognized adjustments to its original estimate of the Plant Acquisition Adjustment (PAA) in the second quarter of 2009.

The adjusted PAA is ($24.2 million), a decrease of $4.1 million from the original estimate of ($28.3 million). The adjusted Transaction and Transition Costs is an increase of $5.4 million over the original estimate, reflecting additional costs to complete the acquisition and financing. Partially offsetting the decrease in the PAA estimate due to the additional Transaction and Transition Costs were subsequent payments, cash settlements between the purchaser and seller and other post-closing adjustments reflecting changes to working capital and Net Utility Plant.

The revised purchase price allocations are as follows:

Purchase Price Allocation
($ Millions)

	December 1, 2008
Equity Purchase Price	$ 160.0
Plus: Working Capital Adjustment	49.2
Aggregate Purchase Price	209.2
Transaction and Transition Costs	13.0
Total Cash Purchase Price	222.2
Allocation To:	
Book Value of Net Utility Plant	(197.0)
Cash Acquired	(6.9)
Accounts Receivable and Other Current Assets	(21.7)
Accrued Revenue	(7.0)
Gas Inventory	(32.3)
Regulatory and Other Noncurrent Assets	(32.8)
Accounts Payable and Other Current Liabilities	20.0
Regulatory Liabilities	31.3
Plant Acquisition Adjustment	**$ (24.2)**

In accordance with settlement agreements between the Company, the New Hampshire Public Utilities Commission (NHPUC) and the Maine Public Utilities Commission (MPUC) regarding the Acquisitions, the Company has agreed (i) not to seek recovery of transaction and transition costs in rates and (ii) for regulatory accounting purposes, to amortize, over a ten year period, the transaction and transition costs co-terminus with the Plant Acquisition Adjustment.

Table of Contents

NOTE 3 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
06/18/09	08/14/09	07/31/09	$0.345
03/26/09	05/15/09	05/01/09	$0.345
01/15/09	02/16/09	02/02/09	$0.345
09/25/08	10/31/08	10/17/08	$0.345
06/19/08	08/15/08	08/01/08	$0.345
03/20/08	05/15/08	05/01/08	$0.345
01/17/08	02/15/08	02/01/08	$0.345

NOTE 4 – COMMON STOCK AND PREFERRED STOCK

Common Stock

As of August 21, 2008 the Company's common stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's common stock trades under the symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 10,816,312, 5,773,452 and 7,791,617 of common shares outstanding at June 30, 2009, June 30, 2008 and December 31, 2008, respectively.

Unitil Corporation Common Stock Offerings – On May 27, 2009, the Company issued and sold 2,400,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2009 Offering). As part of the 2009 Offering, the Company granted the underwriters a 30-day option to purchase up to an additional 360,000 shares to cover any over-allotments. The underwriters exercised their over-allotment option and purchased an additional 300,000 shares of the Company's common stock in June 2009. The Company's net increase to Common Equity and Cash proceeds from the 2009 Offering, including the over-allotment were approximately $51.2 million (after payment of the underwriting discount, but excluding estimated offering expenses) and were used (i) to repay all amounts outstanding under the bridge credit facility (approximately $39.1 million) that the Company used to partially finance the acquisition of Northern Utilities and Granite State which closed on December 1, 2008, and related transaction costs and expenses and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt.

On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2008 Offering). The Company repaid $36.8 million outstanding under the bank financing facility for the Company's acquisitions of Northern Utilities and Granite State with the net proceeds from the sale and issuance of its common stock.

As part of the 2008 Offering, the Company granted the underwriters a 30-day option to purchase up to an additional 300,000 shares to cover any over-allotments. The underwriters exercised their over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the over-allotment sales were approximately $5.1 million (after payment of the underwriting discount, but excluding estimated offering expenses) and were used to repay a portion of the bank financing for the Company's acquisitions of Northern Utilities and Granite State and to repay other short-term indebtedness. The Company recorded the issuance of the 270,000 shares, the sale proceeds and the increase in Common Equity in January 2009.

Table of Contents

Dividend Reinvestment and Stock Purchase Plan – During the first six months of 2009, the Company sold 22,435 shares of its Common Stock, at an average price of $20.72 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $465,000 were used to reduce short-term borrowings.

During the first six months of 2008, the Company sold 14,889 shares of its Common Stock, at an average price of $27.76 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $413,000 were used to reduce short-term borrowings.

Restricted Stock Plan – The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 17, 2009, 32,260 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $661,007. Compensation expense associated with shares issued under the Plan is recognized ratably as the shares vest and was $0.3 million and $0.2 million for the six months ended June 30, 2009 and 2008, respectively. At June 30, 2009, there was approximately $1.4 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 3.1 years as the shares vest. During the six months ended June 30, 2009, 12,459 restricted shares vested. As of June 30, 2009 there were 52,019 unvested restricted shares.

Preferred Stock

Details on preferred stock at June 30, 2009, June 30, 2008 and December 31, 2008 are shown below:

(Amounts in Millions)

	June 30,		December 31,
	2009	**2008**	**2008**
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.8	0.8
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.0**	$ 2.0	$ 2.0

[Table of Contents](#)

NOTE 5 – LONG-TERM DEBT, CREDIT ARRANGEMENTS AND GUARANTEES

Long-Term Debt

Details on long-term debt at June 30, 2009, June 30, 2008 and December 31, 2008 are shown below ($ Millions):

	June 30, 2009	June 30, 2008	December 31, 2008
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Northern Utilities Senior Notes:			
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	—	30.0
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	—	50.0
Granite State Senior Notes:			
7.15% Senior Notes, Due December 15, 2018	**10.0**	—	10.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due Through August 1, 2017	**4.5**	4.8	4.7
Total Long-Term Debt	**249.5**	159.8	249.7
Less: Current Portion	**0.4**	0.4	0.4
Total Long-term Debt, Less Current Portion	**$ 249.1**	$ 159.4	$ 249.3

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield for June 2009. The carrying value of the Company's long-term debt at June 30, 2009 is $249.5 million. The fair value of the Company's long-term debt at June 30, 2009 is estimated to be approximately $247.4 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

Credit Arrangements

At June 30, 2009, the Company had $30.6 million in short-term debt outstanding through bank borrowings under its revolving credit agreement. The revolving credit agreement also contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of June 30, 2009, the Company was in compliance with financial covenants contained in the revolving credit agreement.

On November 1, 2008, Northern Utilities entered into a gas storage management agreement pursuant to which (i) Northern Utilities released certain pipeline and storage capacity to an asset manager from November 1, 2008 through April 30, 2009 and (ii) the asset manager financed inventories associated with the released storage capacity from Northern Utilities contemporaneously with the closing of the Acquisitions. Pursuant to the agreement, Northern Utilities repurchased the storage inventory over the course of the 2008/2009 winter heating season at the same price initially paid by the asset manager. Effective May 1, 2009, Northern entered into a subsequent gas storage management agreement which provides for refilling the storage inventory between May 1, 2009 and October 31, 2009. Similar to the prior agreement, the asset manager is maintaining the cost of the inventory. On October 31, 2009, at the end of the refill period, Northern will purchase the inventory associated with this storage asset. There was $3.1 million and $24.0 million outstanding at June 30, 2009 and December 31, 2008, respectively, related to these agreements.

Guarantees

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of June 30, 2009 there are $18.3 million of guarantees outstanding and the longest of these guarantees extends through December 31, 2010. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of June 30, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.5 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite State notes due 2018. As of June 30, 2009, the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. This guarantee will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Table of Contents

NOTE 6 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and six months ended June 30, 2009 and June 30, 2009 (Millions):

Three Months Ended:	Electric	Gas	Other	Non-Regulated	Total
June 30, 2009					
Revenues	**$ 47.0**	**$ 23.4**	**$ —**	**$ 1.1**	**$ 71.5**
Segment Profit (Loss)	**(0.2)**	**(0.5)**	**0.5**	**0.4**	**0.2**
Capital Expenditures	**1.8**	**6.3**	**—**	**—**	**8.1**
June 30, 2008					
Revenues	$ 52.0	$ 6.6	$ —	$ 0.8	$ 59.4
Segment Profit (Loss)	2.0	(0.3)	(0.1)	—	1.6
Capital Expenditures	5.4	0.2	0.1	—	5.7
Six Months Ended:					
June 30, 2009					
Revenues	**$ 109.1**	**$ 95.8**	**$ —**	**$ 2.2**	**$ 207.1**
Segment Profit (Loss)	**1.3**	**7.1**	**0.1**	**0.8**	**9.3**
Capital Expenditures	**15.1**	**10.9**	**0.1**	**—**	**26.1**
Segment Assets	**344.4**	**338.9**	**10.4**	**0.8**	**694.5**
June 30, 2008					
Revenues	$ 108.6	$ 20.9	$ —	$ 1.8	$ 131.3
Segment Profit (Loss)	2.5	2.5	(0.2)	0.1	4.9
Capital Expenditures	9.6	0.5	0.1	—	10.2
Segment Assets	326.2	108.5	27.9	1.0	463.6

NOTE 7 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2008 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 18, 2009.

Legal Proceedings

A putative class action Complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009 an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. The Company believes the suit is without merit, and will defend itself vigorously.

[Table of Contents](#)

Regulatory Matters

Major Ice Storm – On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Fitchburg was able to restore power to one-third of its Massachusetts customers within three days, 80 percent of its customers by day seven, and the final Massachusetts customers, including those with individual service problems, were restored by December 24, 2008. On January 7, 2009, the MDPU opened an investigation into the preparation and response of the Massachusetts electric distribution companies to the December 12, 2008 Winter Storm. Evidentiary hearings before the MDPU concerning Fitchburg's storm response were held in May, 2009. After the hearing, the Massachusetts Attorney General recommended that the MDPU assess fines against Fitchburg totaling $4.65 million as penalties for Fitchburg's performance during and after the storm. Fitchburg has argued that the Attorney General's recommendation is not supported by the evidence, is contrary to the record of the Company's actual performance, and incorrectly interprets the authority of the MDPU to assess such penalties. A decision by the MDPU regarding the results of its investigation and the recommendation of the Attorney General remains pending.

Based on its preliminary assessment, the Company has accrued and deferred as a regulatory asset, excluding capital construction expenditures, approximately $12.5 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations.

Fitchburg – Electric Division – On November 26, 2008, Fitchburg submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan (the Annual Reconciliation Filing). The rates were approved effective January 1, 2009, subject to reconciliation pursuant to the MDPU's investigation. This matter remains pending before the MDPU.

Fitchburg – Gas Operations – On March 12, 2009, the MDPU opened an investigation into Fitchburg's gas procurement practices. The purpose of this investigation is to determine: (1) whether Fitchburg has engaged in a purchasing program to mitigate the volatility of gas commodity prices without MDPU approval; and, if so, (2) an appropriate remedy, including whether Fitchburg's ratepayers are entitled to reimbursement for any gas supply costs that are higher than they would have been absent such purchasing program. The Company believes that its gas procurement practices have been and remain in compliance and consistent with all relevant MDPU rules and orders and Massachusetts law, and does not believe that the investigation will have a material adverse impact upon the Company's financial condition or the results of its operations. Evidentiary hearings were concluded in June 2009. The Massachusetts Attorney General, an intervener in the MDPU investigation, has argued that Fitchburg was required to obtain MDPU approval of its gas purchasing program, and has recommended that Fitchburg refund to ratepayers $863,368 of gas supply costs. Fitchburg disagrees with the Attorney General's analysis and conclusions and believes that the refund recommendation is without precedent and contrary to the evidence. A decision by the MDPU is expected by the end of the year. This matter remains pending.

Fitchburg – Other – On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "The Green Communities Act" (the GC Act), an energy policy legislation designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced energy efficiency investment plans, plans to establish smart grid pilot programs, and special tariffs to allow the net metering of customer-owned renewable generation. This matter remains pending.

Unitil Energy – On June 17, 2009, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2009, including reconciliation of prior year costs and revenues. This matter remains pending.

Northern Utilities – Notices of Probable Violation – Beginning in October 2007, the MPUC initiated formal investigations into a number of Notices of Probable Violation (NOPVs) alleging that Northern Utilities had violated various provisions of the federal pipeline safety regulations, as adopted by the MPUC. Northern Utilities, the MPUC Staff and Unitil filed a comprehensive settlement (Settlement), which was approved by the MPUC on November 21, 2008, resolving these matters. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for certain safety related improvements for which no rate recovery will be allowed and obligations to be undertaken for Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at June 30, 2009 was $2.3 million.

Northern Utilities – New Hampshire 2007/2008 Winter Cost of Gas – On October 31, 2007, the NHPUC issued Order No. 24,798 concerning the 2007/2008 winter cost of gas proceeding for Northern Utilities' New Hampshire division. In that order, the NHPUC noted that Northern Utilities had identified an unusually high level of lost and unaccounted for gas (UAFG), and ordered Northern Utilities to file a detailed report concerning its investigation of this matter. Through its investigation, Northern Utilities determined that the UAFG affected both its New Hampshire and Maine divisions, and that the cause appeared to be incorrect metering at the Maritimes & Northeast (M&NE) / Portland Natural Gas Transmission System's (PNGTS) Newington Gate Station caused by an erroneous meter module change. The metering equipment was operated and maintained by a third party, Spectra Energy, the parent company of M&NE. PNGTS and M&NE share joint ownership of the section of the pipeline connected to Granite State at the Newington Gate Station. The error caused Granite State to be billed for 758,702 Dth of natural gas, with Granite State then billing Northern Utilities for an equivalent amount, although the volumes of gas were not actually delivered. The meter error was corrected and Northern Utilities, Granite State, Spectra Energy and PNGTS reached an agreement whereby PNGTS will provide to Northern Utilities, through Granite State, gas volumes equal to the misread amounts to correct for the error, over a period of approximately 18 months. Both the NHPUC and the MPUC have approved this arrangement, as well as Northern Utilities' methodology for allocating the gas received to its Maine and New Hampshire divisions based upon the actual gas use over the period the meters were misread. As of June 30, 2009, Northern Utilities has recorded approximately $1.7 million reflecting the anticipated liability of the future refund amount based on current market prices, with an offsetting receivable from Granite State, and Granite State has recorded a receivable from PNGTS for this amount.

Northern Utilities – Maine Capacity Costs – In its October 28, 2008 approval of Northern Utilities' Maine Division's Cost of Gas Factor for the 2008-2009 Winter Period, the MPUC approved recovery of an additional $0.5 million of annual demand costs that had been inadvertently omitted from Northern Utilities' reconciliation of the 2008-2009 Winter Period rates, although analogous costs had been included in its calculation of 2007-2008 Winter Period rates. The MPUC determined that recovery of these Local Production Capacity Costs was consistent with previous MPUC orders and the $0.5 million was recovered in Northern Utility's rates in Maine between November 1, 2008 and April 30, 2009.

Northern Utilities also reported that, upon investigation, these annual demand costs, though approved, were incorrectly excluded from its reconciliation for five previous annual periods. The total impact for the five years is $2.4 million. On November 7, 2008, Northern Utilities, prior to the completion of the acquisition by Unitil, filed a request with the MPUC seeking an accounting order allowing it to defer and amortize for recovery these unrecovered gas costs over a three year period. In its Order dated July 1, 2009, the MPUC denied Northern's request for an accounting order and denied Northern's recovery of the unrecovered annual demand gas costs in future rates. Based on the uncertainty of the outcome of this proceeding, the Company had not recorded a regulatory asset related to this matter and therefore the MPUC's Order does not adversely impact the Company's financial statements.

NOTE 8 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2008 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 18, 2009.

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of June 30, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at June 30, 2009 are current and non-current accrued liabilities totaling $10.8 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties. Also included on the Company's Consolidated Balance Sheet at June 30, 2009 are current and non-current accrued liabilities totaling $2.4 million associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the recovery of these environmental remediation costs is probable through the regulatory process.

NOTE 9 – RETIREMENT BENEFIT OBLIGATIONS

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) – The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.
- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) – The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.
- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) – The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

Table of Contents

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

	2009	2008
Used to Determine Plan Costs		
Discount Rate	**6.25%**	6.00%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017
	2008	**2007**
Used to Determine Benefit Obligations:		
Discount Rate	**6.25%**	6.00%
Rate of Compensation Increase	**3.50%**	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2017

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan		PBOP Plan		SERP	
Three Months Ended June 30,	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**
Service Cost	**$ 571**	$ 488	**$ 357**	$ 355	**$ 54**	$ 37
Interest Cost	**1,074**	943	**579**	559	**45**	31
Expected Return on Plan Assets	**(1,108)**	(1,094)	**(89)**	(82)	**—**	—
Prior Service Cost Amortization	**66**	27	**428**	341	**(1)**	—
Transition Obligation Amortization	**—**	—	**5**	6	**—**	—
Actuarial Loss Amortization	**399**	319	**—**	—	**18**	6
Sub-total	**1,002**	683	**1,280**	1,179	**116**	74
Amounts Capitalized and Deferred	**(364)**	(246)	**(442)**	(513)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 638**	$ 437	**$ 838**	$ 666	**$ 116**	$ 74

Table of Contents

Six Months Ended June 30,	Pension Plan 2009	Pension Plan 2008	PBOP Plan 2009	PBOP Plan 2008	SERP 2009	SERP 2008
Service Cost	**$ 1,142**	$ 976	**$ 714**	$ 710	**$ 108**	$ 74
Interest Cost	**2,147**	1,887	**1,157**	1,118	**90**	63
Expected Return on Plan Assets	**(2,216)**	(2,187)	**(178)**	(163)	**—**	—
Prior Service Cost Amortization	**132**	54	**856**	681	**(1)**	—
Transition Obligation Amortization	**—**	—	**10**	11	**—**	—
Actuarial Loss Amortization	**798**	638	**—**	—	**36**	12
Sub-total	**2,003**	1,368	**2,559**	2,357	**233**	149
Amounts Capitalized and Deferred	**(646)**	(447)	**(800)**	(952)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 1,357**	$ 921	**$ 1,759**	$ 1,405	**$ 233**	$ 149

Employer Contributions

On August 17, 2006, the Pension Protection Act of 006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92%—100%) funding targets available to well-funded plans during the transition period. The Company expects to contribute approximately $4.0 million to fund its Pension Plan in 2009.

As of June 30, 2009, the Company had made $0.5 million and $26,000 of contributions to the PBOP and SERP Plans, respectively, in 2009. The Company presently anticipates contributing an additional $2.3 million and $27,000 to the PBOP and SERP Plans, respectively, in 2009.

NOTE 10 – INCOME TAXES

The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2008 and for the current interim reporting period ended June 30, 2009 in accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2005; December 31, 2006; and December 31, 2007. Income tax filings for the year ended December 31, 2008 have been extended until September 15, 2009. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

NOTE 11 – UNAUDITED PRO FORMA FINANCIAL DATA RELATED TO ACQUISITIONS

On December 1, 2008, the Company acquired Northern Utilities and Granite State, as discussed in Note 1. Had the results of operations for Northern Utilities and Granite State been combined with the Company as of the beginning of 2008, the Company's pro forma results for the three and six months ended June 30, 2008 would have been as follows:

(Millions, except per share amounts) (Unaudited)	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
Revenues	$ 79.7	$ 206.1
Earnings (Loss) Applicable to Common Shareholders	$ (0.4)	$ 7.1
Earnings (Loss) per Share		
Basic	$ (0.04)	$ 0.66
Diluted	$ (0.04)	$ 0.66

The Unaudited Pro Forma Financial Data include non-recurring charges to operating expenses of $1.2 million, after tax, related to compliance violation penalties incurred by Northern Utilities in the second quarter of 2008.

The Unaudited Pro Forma Financial Data are presented for illustrative purposes only and do not indicate the financial results of the combined companies had the companies actually been combined and had the impact of possible revenue enhancements and expense efficiencies, among other factors, been considered, and is not intended to be a projection of future results.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in the Company's internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 7 and 8 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Table of Contents

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2008 as filed with the SEC on February 18, 2009.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended June 30, 2009.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), adopted by the Company on March 26, 2009, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases; however, the trading plan will terminate when $83,000 in value of shares have been purchased or, if sooner, on March 26, 2010.

The Company's repurchases are shown in the table below for the monthly periods noted:

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
4/1/09 – 4/30/09	—	—	—
5/1/09 – 5/31/09	—	—	—
6/1/09 – 6/30/09	373	$ 20.03	373
Total	373	$ 20.03	373

Item 5. Other Information

On July 23, 2009, the Company issued a press release announcing its results of operations for the three- and six-month periods ended June 30, 2009. The press release is furnished with this Quarterly Report on Form 10-Q as Exhibit 99.1.

Table of Contents

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation of Earnings per Weighted Average Common Share Outstanding	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated July 23, 2009 Announcing Earnings For the Quarter Ended June 30, 2009.	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	UNITIL CORPORATION
	(Registrant)
Date: July 24, 2009	/s/ Mark H. Collin
	Mark H. Collin Chief Financial Officer
Date: July 24, 2009	/s/ Laurence M. Brock
	Laurence M. Brock Chief Accounting Officer

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description of Exhibit	Reference
11	Computation of Earnings per Weighted Average Common Share Outstanding	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated July 23, 2009 Announcing Earnings For the Quarter Ended June 30, 2009.	Filed herewith

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER WEIGHTED AVERAGE COMMON SHARE OUTSTANDING

(Millions except common shares and per share data)

(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Net Income	**$ 0.3**	$ 1.7	**$ 9.4**	$ 5.0
Less: Dividend Requirements on Preferred Stock	**0.1**	0.1	**0.1**	0.1
Net Income Applicable to Common Stock	**$ 0.2**	$ 1.6	**$ 9.3**	$ 4.9
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**9,014**	5,736	**8,516**	5,728
Dilutive Effect of Stock Options and Restricted Stock (000's)	**—**	5	**—**	5
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**9,014**	5,741	**8,516**	5,733
Earnings Per Share – Basic	**$ 0.03**	$ 0.28	**$ 1.10**	$ 0.85
Earnings Per Share – Diluted	**$ 0.03**	$ 0.28	**$ 1.10**	$ 0.85

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 24, 2009
/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 24, 2009
/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 24, 2009
/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	July 24, 2009
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	July 24, 2009
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	July 24, 2009

Exhibit 99.1

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports Second Quarter Earnings

Hampton, NH – July 23, 2009: Unitil Corporation (NYSE: UTL) (www.unitil.com) today announced Earnings Applicable to Common Shareholders of $0.2 million for the second quarter of 2009, compared to earnings of $1.6 million for the second quarter of 2008. Earnings per common share (EPS) were $0.03 for the three months ended June 30, 2009 compared with $0.28 in the second quarter of 2008. For the six months ended June 30, EPS were $1.10 for 2009 compared to $0.85 for 2008, an increase of $0.25 per share, or 29%, reflecting the positive impact from the acquisition of Northern Utilities, Inc. (Northern Utilities) and Granite State Gas Transmission, Inc. (Granite State). Earnings in the second quarter reflect higher gas utility sales margins offset by lower electric utility sales margins and higher operating, depreciation and interest costs in the quarter as well as a higher number of average shares outstanding year over year, discussed below.

"We saw the positive impact of the Northern Utilities and Granite State acquisition on the Company's earnings for the six month period ending in June, while the quarterly results show the greater seasonality due to our diverse portfolio of gas and electric business operations," said Robert G. Schoenberger, Unitil's Chairman and Chief Executive Officer. "We have also completed the planned financings associated with the acquisition and successfully transitioned all key business operations for Northern Utilities and Granite State to Unitil's systems and processes."

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in current and future reporting periods will reflect to a greater degree the seasonal nature of the natural gas business by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of current and future reporting years.

Natural gas sales margin increased $8.4 million and $26.5 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the contribution by Northern Utilities, the Company's recently acquired local gas distribution utility. Natural gas sales in the six month period ended June 30, 2009 reflect a colder winter heating season this year. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

Electric sales margin decreased $1.6 million and $0.3 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008, reflecting lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 6.8% and 5.7% in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008 due to lower average usage by our customers reflecting the continued regional economic slowdown.

Selected Financial Data for 2009 is presented in the following table:

Unitil Corporation - Condensed Financial Data

(Millions, except Per Share data) (Unaudited)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	**2008**	**Change**	**2009**	**2008**	**Change**
Gas Therm Sales: (a)						
Residential	6.9	2.1	228.6%	26.2	6.9	279.7%
Commercial/Industrial	28.5	4.1	595.1%	86.6	10.9	694.5%
Total Gas Therm Sales	**35.4**	**6.2**	**471.0%**	**112.8**	**17.8**	**533.7%**
Electric kWh Sales:						
Residential	141.1	147.5	(4.3%)	321.7	329.9	(2.5%)
Commercial/Industrial	233.2	254.0	(8.2%)	475.3	515.1	(7.7%)
Total Electric kWh Sales	**374.3**	**401.5**	**(6.8%)**	**797.0**	**845.0**	**(5.7%)**
(a) 2009 Gas Therm Sales include Northern Utilities, Inc., acquired on December 1, 2008.						
Gas Revenues	$ 23.4	$ 6.6	$ 16.8	$ 95.8	$ 20.9	$ 74.9
Purchased Gas	12.4	4.0	8.4	61.4	13.0	48.4
Gas Sales Margin	**11.0**	**2.6**	**8.4**	**34.4**	**7.9**	**26.5**
Electric Revenues	47.0	52.0	(5.0)	109.1	108.6	0.5
Purchased Electricity	34.2	37.6	(3.4)	81.9	81.1	0.8
Electric Sales Margin	**12.8**	**14.4**	**(1.6)**	**27.2**	**27.5**	**(0.3)**
Usource Sales Margin	**1.1**	**0.8**	**0.3**	**2.2**	**1.8**	**0.4**
Total Sales Margin:	**24.9**	**17.8**	**7.1**	**63.8**	**37.2**	**26.6**
Operation & Maintenance Expenses	12.0	7.0	5.0	22.4	11.7	10.7
Depreciation, Amortization & Other	9.0	6.9	2.1	23.6	15.7	7.9
Interest Expense, Net	3.7	2.3	1.4	8.5	4.9	3.6
Earnings App. to Common Shareholders:	**$ 0.2**	**$ 1.6**	**$ (1.4)**	**$ 9.3**	**$ 4.9**	**$ 4.4**
Earnings Per Share	**$ 0.03**	**$ 0.28**	**$ (0.25)**	**$ 1.10**	**$ 0.85**	**$ 0.25**

Operation & Maintenance (O&M) expenses increased $5.0 million and $10.7 million for the three and six months ended June 30, 2009, respectively, compared to the same period in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $4.3 million of the increase in the six month period. For the six month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees expense of $1.9 million, primarily related to the internal review and legal and regulatory proceedings associated with the ice storm of December 2008, higher compensation and employee benefit expenses of $0.6 million and higher other utility operating costs of $1.1 million contributed to the increase in O&M expenses. The increase in O&M expenses for the six month period also reflects higher insurance costs in 2009 compared to the same period in 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Depreciation, Amortization, Taxes and Other expenses increased $2.1 million and $7.9 million in the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008. The increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs.

Interest Expense, Net, increased $1.4 million and $3.6 million in the three and six month periods ended June 30, 2009, respectively, compared to the same periods in 2008. These increases are primarily due to the addition of Northern Utilities and Granite State, reflecting the issuance of long-term notes by Northern Utilities and Granite State in December 2008. In addition, these increases in Interest Expense, Net, reflect higher average borrowings in the current periods.

Also in the second quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

Between December 2008 and June 2009, the Company issued and sold 4,970,000 shares of its common stock, including its underwriters' exercise of overallotment options to purchase an additional 570,000 shares, at a price of $20.00 per share in registered public offerings. The Company used net proceeds of $93.1 million from these offerings (i) to repay all amounts outstanding under the bridge credit facility that the Company used to partially finance the acquisition of Northern Utilities and Granite State that closed on December 1, 2008 and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt. Overall, the positive results of operations and net income are reflected over a higher number of average shares outstanding year over year.

About Unitil

Unitil is a public utility holding company with subsidiaries providing electric and natural gas distribution service in New Hampshire and Massachusetts, natural gas distribution service in Maine and energy services throughout the northeast. Unitil serves approximately 170,000 utility customers in three states. Its utility affiliates include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc. and Granite State Gas Transmission, Inc. Its other subsidiaries include Unitil Service Corp. and its non-regulated business segment doing business as Usource.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended September 30, 2009

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	**(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 22, 2009
Common Stock, No par value	**10,826,827 Shares**

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended September 30, 2009

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the Federal Energy Regulatory Commission (the "FERC") under the Energy Policy Act of 2005.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly owned distribution utilities: (i) Unitil Energy Systems, Inc. (Unitil Energy), which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, including the city of Concord, New Hampshire; (ii) Fitchburg Gas and Electric Light Company (Fitchburg), which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and (iii) Northern Utilities, Inc. (Northern Utilities), which provides natural gas service in southeastern New Hampshire, including the city of Portsmouth, and portions of southern and central Maine, including the city of Portland. In addition, Unitil is the parent company of Granite State Gas Transmission, Inc. (Granite State), an interstate natural gas transmission pipeline company that principally provides interstate natural gas pipeline access and transportation services to Northern Utilities in its New Hampshire and Maine service territory.

The Company's distribution utilities serve approximately 100,300 electric customers and 69,300 natural gas customers in their service territory. The Company's distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in Net Utility Plant of $437.9 million at September 30, 2009. The Company does not own or operate electric generating facilities and substantially all of the Company's utility assets are dedicated to the local delivery of electricity and natural gas to its customers. Substantially all of Unitil's revenue is derived from regulated utility operations.

On December 1, 2008, Unitil purchased (i) all of the outstanding capital stock of Northern Utilities from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State from NiSource Inc. (NiSource) pursuant to the Stock Purchase Agreement dated as of February 15, 2008 by and among NiSource, Bay State and Unitil (the "Acquisitions"). Bay State is a wholly owned subsidiary of NiSource. The aggregate purchase price for the Acquisitions was $160 million in cash, plus an additional working capital adjustment of $49.2 million, including approximately $30.0 million of natural gas storage inventory. To finance the Acquisitions and recapitalize Northern Utilities and Granite State, the Company issued additional equity and debt.

A fifth wholly owned subsidiary, Unitil Power Corp. (Unitil Power), formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

The Company also has three other wholly owned subsidiaries: Unitil Service Corp. (Unitil Service); Unitil Realty Corp. (Unitil Realty); and Unitil Resources, Inc. (Unitil Resources). Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire. Unitil Resources is the Company's wholly owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, "Usource") are indirect subsidiaries that are wholly owned by Unitil Resources. Usource provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Table of Contents

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, in regards to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and the Maine Public Utilities Commission (MPUC). Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party suppliers. A majority of Unitil's largest commercial and industrial (C&I) customers purchase their electric and natural gas supplies from third party suppliers. However, most residential and small customers continue to purchase their electric and natural gas supplies through Unitil's distribution utilities. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features. For additional discussion, please refer to Unitil's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 18, 2009.

CAUTIONARY STATEMENT

This report and the documents the Company incorporates by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's and its management's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Part II, Item 1A (Risk Factors) and the following:

- The Company's ability to integrate the business, operations and personnel of Northern Utilities and Granite State and to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;

- General economic conditions, including recent distress in the financial markets that has had an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of the Company's counterparty obligations, including those of Unitil's insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

ACCOUNTING PRONOUNCEMENTS

In June 2009, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 168), a replacement of SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles". SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States. SFAS No. 168 is effective for financial statements for interim and annual periods ending after September 15, 2009. SFAS No. 168 establishes the FASB Accounting Standards Codification (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with Generally Accepted Accounting Principles. The purpose of the Codification is to simplify U.S. GAAP, without change, by consolidating the numerous accounting rules into logically organized topics. The Company has adopted SFAS No. 168 and therefore all references by the Company to authoritative accounting principles recognized by the FASB reflect the Codification.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended September 30, 2009 and September 30, 2008 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Part I, Item 1 of this report.

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company's results will reflect the seasonal nature of the natural gas business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders was a loss of ($0.6) million for the third quarter of 2009, compared to earnings of $1.5 million for the third quarter of 2008. Earnings (loss) per common share (EPS) were ($0.06) for the three months ended September 30, 2009 compared with $0.27 in the third quarter of 2008. For the nine months ended September 30, 2009, the Company reported net income of $8.7 million, an increase of $2.3 million over the same period of 2008, reflecting the acquisitions of Northern Utilities and Granite State. EPS for the nine months ended September 30 were $0.94 for 2009 compared to $1.12 for 2008, reflecting a higher number of average shares outstanding year over year, discussed below.

Between December 2008 and June 2009, the Company sold 4,970,000 shares of its common stock at a price of $20.00 per share in registered public offerings. The Company used the net proceeds of $93.1 million from these offerings to finance the acquisition of Northern Utilities and Granite State and for capital contributions to Unitil's other distribution utilities and the repayment of short-term debt. Overall, the results of operations and net income are reflected over a higher number of average shares outstanding year over year.

Earnings in the third quarter reflect higher gas utility sales margins offset by higher operating, depreciation and interest costs in the quarter as well as a higher number of average shares outstanding year over year, discussed above. Natural gas sales margin increased $5.9 million and $32.4 million in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the contribution by Northern Utilities, the Company's recently acquired local gas distribution utility. Natural gas sales in the nine month period ended September 30, 2009 reflect a colder winter heating season this year. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

Electric sales margin increased $0.2 million in the three months ended September 30, 2009 compared to the same period in 2008, reflecting higher rates offset by lower sales. For the nine months ended September 30, 2009, electric sales margin decreased $0.1 million, compared to the same period in 2008, reflecting lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 4.5% and 5.3% in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008 due to lower average usage by our customers reflecting the continued regional economic slowdown and milder summer weather in 2009.

Total Operation & Maintenance (O&M) expenses increased $5.0 million and $15.7 million for the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $7.7 million of the increase in the nine month period. For the nine month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees expense of $2.3 million, including $2.0 million of costs related to the December ice storm discussed below, higher compensation and employee benefit expenses of $1.3 million and higher utility operating costs of $1.6 million contributed to the increase in O&M expenses. The increase in O&M expenses for the nine month period also reflects higher insurance costs in 2009 compared to the same period in 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Depreciation, Amortization, Taxes and Other expenses increased $1.5 million and $9.4 million in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. The increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs and lower income taxes on lower pre-tax earnings for the three month period.

Interest Expense, Net increased $1.6 million and $5.2 million in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2009. These increases are primarily due to the addition of Northern Utilities and Granite State, reflecting the issuance of long-term notes by Northern Utilities and Granite State in December 2008. In addition, these increases in Interest Expense, Net reflect higher average borrowings in the current periods.

Usource, our non-regulated energy brokering business, recorded revenues of $1.0 million and $3.2 million in the three and nine month periods ended September 30, 2009, respectively, a decrease of $0.1 million and an increase of $0.3 million compared to the same periods of 2008. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

On December 11 and 12, 2008, a severe ice storm struck the New England region, creating extended power outages for many residents of Massachusetts and New Hampshire, including Unitil's electric customers in New Hampshire and the greater Fitchburg, Massachusetts service territory. Based on its preliminary assessment, the Company has accrued and deferred, excluding capital construction expenditures, approximately $14.1 million in costs for the repair and replacement of electric distribution systems damaged during the storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations.

Table of Contents

In 2008, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2009, March, 2009, June, 2009 and September 2009 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three and nine months ended September 30, 2009 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

The Company's Total Assets increased by $243.7 million as of September 30, 2009 compared to September 30, 2008. The increase in Total Assets was primarily due to the inclusion of the acquisitions of Northern Utilities and Granite State and to capital expenditures related to Unitil Energy's and Fitchburg's electric and gas distribution systems. The Company's Total Capitalization increased by $181.3 million as of September 30, 2009 compared to September 30, 2008 reflecting the issuance of common shares by the Company as part of its financing of the acquisitions of Northern Utilities and Granite State (See Note 4 to the accompanying Consolidated Financial Statements) and the issuance and sale of Senior Unsecured Notes by Northern Utilities and Granite State (See Note 5 to the accompanying Consolidated Financial Statements). The Company's Total Liabilities increased $62.4 million primarily due to the acquisitions of Northern Utilities and Granite State.

Gas Sales, Revenues and Margin

Therm Sales – Overall, Unitil's total therm sales of natural gas increased in the three and nine month periods ended September 30, 2009 compared to the same periods in 2008. These increases primarily reflect the contribution of sales by Northern Utilities. Excluding the contribution to sales by Northern Utilities, total therm sales of natural gas were flat in the three months ended September 30, 2009 compared to the same period in 2008 and increased 0.5% in the nine months ended September 30, 2009 compared to the same period in 2008. The increase in the nine month period ended September 30, 2009 reflects a colder winter heating season this year. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

The following table details total firm therm sales for the three and nine months ended September 30, 2009 and 2008, by major customer class:

Therm Sales (millions) (a)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	**2008**	**Change**	**% Change**	**2009**	**2008**	**Change**	**% Change**
Residential	**2.9**	0.7	2.2	314.3%	**29.1**	7.7	21.4	277.9%
Commercial / Industrial	**19.5**	3.0	16.5	550.0%	**106.1**	13.9	92.2	663.3%
Total	**22.4**	3.7	18.7	505.4%	**135.2**	21.6	113.6	525.9%

(a) 2009 Therm Sales include Northern Utilities, acquired on December 1, 2008.

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and nine months ended September 30, 2009 and 2008:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	**2008**	**$ Change**	**% Change(1)**	**2009**	**2008**	**$ Change**	**% Change(1)**
Gas Operating Revenue:								
Residential	**$ 5.7**	$ 2.1	$ 3.6	81.8%	**$ 45.9**	$ 13.7	$ 32.2	127.3%
Commercial / Industrial	**9.5**	2.3	7.2	163.6%	**65.1**	11.6	53.5	211.5%
Total Gas Operating Revenue	**$ 15.2**	$ 4.4	$ 10.8	245.4%	**$ 111.0**	$ 25.3	$ 85.7	338.8%
Cost of Gas Sales:								
Purchased Gas	**$ 6.9**	$ 2.4	$ 4.5	102.3%	**$ 67.1**	$ 15.3	$ 51.8	204.7%
Conservation & Load Management	**0.4**	—	0.4	9.1%	**1.6**	0.1	1.5	5.9%
Gas Sales Margin	**$ 7.9**	$ 2.0	$ 5.9	134.0%	**$ 42.3**	$ 9.9	$ 32.4	128.2%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $10.8 million and $85.7 million in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the natural gas sales for Northern Utilities. Total Gas Operating Revenues include the recovery of the cost of gas sales, which are recorded as Purchased Gas and Conservation & Load Management (C&LM) in Operating Expenses. The increase in Total Gas Operating Revenues in the third quarter of 2009 reflects higher Purchased Gas costs of $4.5 million, higher C&LM revenues of $0.4 million and higher gas sales margin of $5.9 million. The increase in Total Gas Operating Revenues in the first nine months of 2009 reflects higher Purchased Gas costs of $51.8 million, higher C&LM revenues of $1.5 million and higher gas sales margin of $32.4 million.

The Purchased Gas and C&LM component of Gas Operating Revenues increased $4.9 million and $53.3 million in the three and nine month periods ended September 30, 2009 compared to the same periods in 2008. These increases primarily reflect the natural gas sales for Northern Utilities. Purchased Gas revenues include the recovery of the cost of gas supply as well as other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $5.9 million and $32.4 million in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the contribution by Northern Utilities.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Unitil's total electric kilowatt-hour (kWh) sales decreased 4.5% and 5.3% in the three and nine month periods ended September 30, 2009, respectively compared to the same periods in 2008. Electric kWh sales to residential customers in the three and nine month periods ended September 30, 2009 decreased 2.4% in each of those periods compared to the same three and nine month periods in 2008 while sales to C&I customers decreased 5.9% and 7.1%, respectively, in those periods compared to the same periods in 2008. The lower kWh sales in 2009 compared to 2008 reflect lower average usage by our customers due to the continued regional economic slowdown and milder summer weather in 2009.

Table of Contents

The following table details total kWh sales for the three and nine months ended September 30, 2009 and 2008 by major customer class:

kWh Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	2008	Change	% Change	2009	2008	Change	% Change
Residential	**172.1**	176.3	(4.2)	(2.4%)	**493.8**	506.2	(12.4)	(2.4%)
Commercial / Industrial	**263.0**	279.4	(16.4)	(5.9%)	**738.3**	794.5	(56.2)	(7.1%)
Total	**435.1**	455.7	(20.6)	(4.5%)	**1,232.1**	1,300.7	(68.6)	(5.3%)

Electric Operating Revenues and Sales Margin – The following table details total Electric Operating Revenues and Sales Margin for the three and nine month periods ended September 30, 2009 and 2008:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	2008	$ Change	% Change(1)	2009	2008	$ Change	% Change(1)
Electric Operating Revenue:								
Residential	**$ 27.9**	$ 30.9	$ (3.0)	(4.7%)	**$ 84.3**	$ 87.0	$ (2.7)	(1.6%)
Commercial / Industrial	**26.3**	32.7	(6.4)	(10.1%)	**79.0**	85.2	(6.2)	(3.6%)
Total Electric Operating Revenue	**$ 54.2**	$ 63.6	$ (9.4)	(14.8%)	**$ 163.3**	$ 172.2	$ (8.9)	(5.2%)
Cost of Electric Sales:								
Purchased Electricity	**$ 38.9**	$ 48.7	$ (9.8)	(15.4%)	**$ 119.5**	$ 128.4	$ (8.9)	(5.2%)
Conservation & Load Management	**0.8**	0.6	0.2	0.3%	**2.1**	2.0	0.1	0.1%
Electric Sales Margin	**$ 14.5**	$ 14.3	$ 0.2	0.3%	**$ 41.7**	$ 41.8	$ (0.1)	(0.1%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenue, decreased by $9.4 million, or 14.8%, and $8.9 million, or 5.2%, in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008. Total Electric Operating Revenues include the recovery of the cost of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The decrease in Total Electric Operating Revenues in the third quarter of 2009 reflects lower Purchased Electricity costs of $9.8 million, partially offset by higher C&LM revenues of $0.2 million and higher electric sales margin of $0.2 million. The decrease in Total Electric Operating Revenues in the first nine months of 2009 reflects lower Purchased Electricity costs of $8.9 million and lower electric sales margin of $0.1 million, partially offset by higher C&LM revenues of $0.1 million.

The Purchased Electricity and C&LM component of Total Electric Operating Revenues decreased $9.6 million, or 15.1%, and $8.8 million, or 5.1%, in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008. These decreases primarily reflect lower sales volumes and lower electric commodity prices, partially offset by higher spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $0.2 million in the three months ended September 30, 2009 compared to the same period in 2008, reflecting higher rates offset by lower sales. For the nine months ended September 30, 2009, electric sales margin decreased $0.1 million, compared to the same period in 2008, reflecting lower sales volumes.

Table of Contents

Operating Revenue - Other

The following table details total Other Revenue for the three and nine months ended September 30, 2009 and 2008:

Other Revenue (000's)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009	**2008**	**$ Change**	**% Change**	**2009**	**2008**	**$ Change**	**% Change**
Other	**$ 1.0**	$ 1.1	$ (0.1)	(9.1%)	**$ 3.2**	$ 2.9	$ 0.3	10.3%
Total Other Revenue	**$ 1.0**	$ 1.1	$ (0.1)	(9.1%)	**$ 3.2**	$ 2.9	$ 0.3	10.3%

Total Other Revenue decreased $0.1 million, or 9.1% and increased $0.3 million, or 10.3%, in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008, representing changes in period over period revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $4.5 million and $51.8 million in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the natural gas supply purchases for Northern Utilities, which were not included in the prior year period. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity decreased $9.8 million, or 20.1%, and $8.9 million, or 6.9%, in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008. These decreases primarily reflect lower electric commodity prices and lower sales volumes in the current periods. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expenses increased $5.0 million and $15.7 million for the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $3.4 million and $7.7 million of the increases in the three and nine month periods, respectively.

For the three month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees of $0.4 million, higher compensation and employee benefit expenses of $0.7 million, reflecting normal annual increases, and higher utility operating costs of $0.5 million contributed to the increase in O&M expenses.

For the nine month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees expense of $2.3 million, including $2.0 million of costs related to the December ice storm discussed above, higher compensation and employee benefit expenses of $1.3 million and higher utility operating costs of $1.6 million contributed to the increase in O&M expenses. The increase in O&M expenses for the nine month period also reflects higher insurance costs in 2009 compared to the same period in 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Conservation & Load Management – Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy usage. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 60% of these costs are related to electric operations and 40% to gas operations.

Total C&LM expenses increased $0.6 million, or 100.0% and $1.6 million, or 76.2%, in the three and nine month periods ended September 30, 2009 compared to the same periods in 2008. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Depreciation, Amortization and Taxes

***Depreciation and Amortization* –** Depreciation and Amortization expense increased $2.0 million, or 43.5% and $5.0 million, or 35.0% in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs.

***Local Property and Other Taxes* –** Local Property and Other Taxes increased $1.0 million and $3.1 million in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher local property tax rates on higher levels of utility plant in service.

***Federal and State Income Taxes* –** Federal and State Income Taxes were lower by $1.5 million in the three month period ended September 30, 2009 compared to the same period in 2008 reflecting lower pre-tax earnings. Federal and State Income Taxes were higher by $1.4 million in the nine month period ended September 30, 2009 compared to the same period in 2008 reflecting higher pre-tax earnings.

Other Non-operating Expenses (Income)

Other Non-operating Expenses were flat in the three month period ended September 30, 2009 compared to the same period in 2008. For the nine month period ended September 30, 2009, Other Non-operating Expenses decreased $0.1 million compared to the same period in 2008. This change reflects an adjustment of $0.1 million recorded in the first quarter of 2008 in conjunction with the Company's approved electric base distribution rate increase in Massachusetts.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (Millions)	Three Months Ended September 30, 2009	2008	Change	Nine Months Ended September 30, 2009	2008	Change
Interest Expense						
Long-term Debt	**$ 4.5**	$ 2.9	$ 1.6	**$ 13.7**	$ 8.6	$ 5.1
Short-term Debt	**0.5**	0.2	0.3	**1.6**	0.7	0.9
Regulatory Liabilities	**0.1**	—	0.1	**0.2**	0.1	0.1
Subtotal Interest Expense	**5.1**	3.1	2.0	**15.5**	9.4	6.1
Interest (Income)						
Regulatory Assets	**(0.6)**	(0.6)	—	**(1.9)**	(1.9)	—
AFUDC[1] and Other	**(0.5)**	(0.1)	(0.4)	**(1.1)**	(0.2)	(0.9)
Subtotal Interest (Income)	**(1.1)**	(0.7)	(0.4)	**(3.0)**	(2.1)	(0.9)
Total Interest Expense, Net	**$ 4.0**	$ 2.4	$ 1.6	**$ 12.5**	$ 7.3	$ 5.2

(1) AFUDC – Allowance for Funds Used During Construction.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

Interest Expense, Net increased $1.6 million and $5.2 million in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2009. These increases were primarily due to the issuance of the long-term notes, noted above, and higher average borrowings in the current periods.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank credit facilities. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

At September 30, 2009, the Company had $54.0 million in short-term debt outstanding through bank borrowings under its revolving credit agreement. The revolving credit agreement contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of September 30, 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 13, 2009, the Company entered into an amendment to its 364-day revolving credit facility with Bank of America, as administrative agent, and a syndicate of lenders. The Company originally entered into the facility on November 26, 2008. The amendment increases the maximum borrowings under the facility from $60 million to $80 million. It also (i) decreases the upfront fees to 15 basis points of the aggregate commitment, (ii) changes the commitment fees from 30 to 40 basis points per annum of the average difference between the aggregate commitment and the outstanding borrowings, (iii) changes the margin applicable to borrowings from 1.75% to 2.0% per annum, and (iv) extends the maturity date for borrowings to October 12, 2010. Except as expressly amended by the amendment, all other terms and conditions of the facility remain in full force and effect.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2009, there were approximately $21.3 million of guarantees outstanding and the longest term guarantee extends through December 31, 2010.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of September 30, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.4 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. The guarantee related to the Granite State notes will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Cash Flows

On December 1, 2008, the Company acquired Northern Utilities and Granite State. Cash flow results for the first nine months of 2009 include the activity for the acquired companies. Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for the nine months ended September 30, 2009 compared to the same period in 2008.

	Nine Months Ended Sept. 30,	
	2009	2008
Cash Provided by Operating Activities	**$ 21.2**	$ 27.1

Cash Provided by Operating Activities – Cash Provided by Operating Activities was $21.2 million during the nine months ended September 30, 2009, a decrease of $5.9 million over the comparable period in 2008. In the first nine months of 2009 as compared to the first nine months of 2008, Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes increased by $10.0 million, sources of cash for working capital increased $2.4 million, and all other sources and uses of cash from Operating Activities decreased $18.3 million, primarily related to the funding in 2009 of non-recurring deferred regulatory charges related to the December 2008 ice storm of $14.0 million.

	Nine Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2008
Cash (Used in) Investing Activities	**$ (49.8)**	$ (20.6)

Cash (Used in) Investing Activities – Cash (Used in) Investing Activities was $49.8 million for the nine months ended September 30, 2009, which represents an increase in capital spending of $29.2 million over the comparable period in 2008. In the nine months ended September 30, 2009, $14.4 million is related to capital expenditures for Northern Utilities and Granite State and $6.8 million represents transaction and transition costs incurred in 2009 associated with the acquisitions of Northern Utilities and Granite State.

	Nine Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2008
Cash Provided by (Used in) Financing Activities	**$ 26.1**	$ (6.1)

Cash Provided by (Used in) Financing Activities – Cash Provided by Financing Activities was $26.1 million in the nine months ended September 30, 2009. Proceeds from the issuance of Common Stock of $56.2 million primarily reflect the issuance of common stock by the Company through public offerings, as discussed above (See Note 4 also). Short-term borrowings were reduced by $20.1 million in the first nine months of 2009 which reflects the net borrowing (repayment) of bank borrowings under our revolving credit agreement and also includes the repayment of $39.1 million outstanding under the temporary bank credit facility utilized in financing the acquisition of Northern Utilities and Granite State. Other uses of cash include $9.4 million for Unitil's regular quarterly dividend payments on Common and Preferred Stock, and $0.6 million which includes repayment of long-term debt and capital lease activity.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 18, 2009.

Regulatory Accounting – The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy is regulated by the FERC and the NHPUC. Fitchburg is regulated by the FERC and the MDPU. Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980-340, "Regulated Operations – Other Assets and Deferred Costs" (ASC 980-340). In accordance with ASC 980-340, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)

	September 30, 2009	September 30, 2008	December 31, 2008
Energy Supply Contract Obligations	**$ 38.1**	$ 57.7	$ 52.7
Deferred Regulatory and Other Charges	**42.3**	28.1	28.3
Generation-related Assets	**0.2**	1.0	0.8
Subtotal – Restructuring Related Items	**80.6**	86.8	81.8
Retirement Benefit Obligations	**46.4**	35.2	45.5
Income Taxes	**15.1**	13.4	16.0
Environmental Obligations	**21.3**	11.6	19.7
Other	**8.2**	3.3	10.1
Total Regulatory Assets	**$ 171.6**	$ 150.3	$ 173.1
Less: Current Portion of Regulatory Assets[1]	**21.0**	21.8	26.9
Regulatory Assets - noncurrent	**$ 150.6**	$ 128.5	$ 146.2

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980-340. If unable to continue to apply the provisions of ASC 980-340, the Company would be required to apply the provisions of ASC 980-20, "Regulated Operations – Discontinuation of Rate Regulated Accounting". In the Company's opinion, its regulated operations will be subject to ASC 980-340 for the foreseeable future.

Utility Revenue Recognition – Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts – The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate reconciliation mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations – The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued ASC 715, "Compensation – Retirement Benefits", (ASC 715). ASC 715 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2008 and 2007, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2008 and 2007, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $675,000 and $690,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $531,000 and $539,000, respectively. (See Note 9 to the accompanying Consolidated Financial Statements).

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with ASC 740, "Income Taxes".

Depreciation – Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies – The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with ASC 450, "Contingencies", (ASC 450). ASC 450 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of September 30, 2009, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

As of September 30, 2009, 149 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two agreements expire on May 31, 2010, one agreement expires on June 5, 2010 and one agreement expires on March 31, 2012. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rates on the Company's short-term borrowings for the three months ended September 30, 2009 and September 30, 2008 were 2.05% and 3.03%, respectively. The average interest rates on the Company's short-term borrowings for the nine months ended September 30, 2009 and September 30, 2008 were 3.82% and 3.28%, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 8 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Table of Contents

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Operating Revenues				
Gas	**$ 15.2**	$ 4.4	**$ 111.0**	$ 25.3
Electric	**54.2**	63.6	**163.3**	172.2
Other	**1.0**	1.1	**3.2**	2.9
Total Operating Revenues	**70.4**	69.1	**277.5**	200.4
Operating Expenses				
Purchased Gas	**6.9**	2.4	**67.1**	15.3
Purchased Electricity	**38.9**	48.7	**119.5**	128.4
Operation and Maintenance	**12.0**	7.0	**34.4**	18.7
Conservation & Load Management	**1.2**	0.6	**3.7**	2.1
Depreciation and Amortization	**6.6**	4.6	**19.3**	14.3
Provisions for Taxes:				
Local Property and Other	**2.4**	1.4	**7.6**	4.5
Federal and State Income	**(1.0)**	0.5	**4.4**	3.0
Total Operating Expenses	**67.0**	65.2	**256.0**	186.3
Operating Income	**3.4**	3.9	**21.5**	14.1
Non-Operating Expenses	**—**	—	**0.2**	0.3
Income Before Interest Expense	**3.4**	3.9	**21.3**	13.8
Interest Expense, Net	**4.0**	2.4	**12.5**	7.3
Net Income (Loss)	**(0.6)**	1.5	**8.8**	6.5
Less: Dividends on Preferred Stock	**—**	—	**0.1**	0.1
Earnings (Loss) Applicable to Common Shareholders	**$ (0.6)**	$ 1.5	**$ 8.7**	$ 6.4
Average Common Shares Outstanding – Basic (000's)	**10,767**	5,745	**9,267**	5,733
Average Common Shares Outstanding – Diluted (000's)	**10,767**	5,748	**9,267**	5,738
Earnings Per Common Share (Basic and Diluted)	**$ (0.06)**	$ 0.27	**$ 0.94**	$ 1.12
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.38**	$ 1.38

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) September 30, 2009	(UNAUDITED) September 30, 2008	December 31, 2008
ASSETS:			
Utility Plant:			
Electric	**$ 300.0**	$ 275.5	$ 289.0
Gas	**316.9**	71.3	304.2
Common	**28.8**	27.3	30.5
Construction Work in Progress	**19.6**	10.9	17.7
Total Utility Plant	**665.3**	385.0	641.4
Less: Accumulated Depreciation	**227.4**	129.0	218.6
Net Utility Plant	**437.9**	256.0	422.8
Current Assets:			
Cash	**9.0**	5.0	11.5
Accounts Receivable – Net of Allowance for Doubtful Accounts of $2.4, $1.3 and $3.0	**27.2**	23.2	39.7
Accrued Revenue	**34.0**	36.5	56.9
Gas Inventory	**13.8**	3.2	31.6
Materials and Supplies	**2.9**	1.9	2.7
Prepayments and Other	**8.3**	2.1	5.9
Total Current Assets	**95.2**	71.9	148.3
Noncurrent Assets:			
Regulatory Assets	**150.6**	128.5	146.2
Other Noncurrent Assets	**27.5**	11.1	15.9
Total Noncurrent Assets	**178.1**	139.6	162.1
TOTAL	**$ 711.2**	$ 467.5	$ 733.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) September 30, 2009	(UNAUDITED) September 30, 2008	December 31, 2008
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 191.6**	$ 99.9	$ 139.5
Preferred Stock	**2.0**	2.0	2.0
Long-Term Debt, Less Current Portion	**249.0**	159.4	249.3
Total Capitalization	**442.6**	261.3	390.8
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.4	0.4
Accounts Payable	**18.6**	18.0	36.3
Short-Term Debt	**54.0**	21.7	74.1
Energy Supply Contract Obligations	**21.4**	19.6	42.0
Other Current Liabilities	**25.0**	10.2	33.8
Total Current Liabilities	**119.4**	69.9	186.6
Deferred Income Taxes	**38.2**	34.4	31.1
Noncurrent Liabilities:			
Energy Supply Contract Obligations	**24.3**	38.1	34.6
Retirement Benefit Obligations	**69.2**	49.5	67.4
Environmental Obligations	**10.9**	12.0	12.3
Other Noncurrent Liabilities	**6.6**	2.3	10.4
Total Noncurrent Liabilities	**111.0**	101.9	124.7
TOTAL	**$ 711.2**	$ 467.5	$ 733.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Operating Activities:		
Net Income	**$ 8.8**	$ 6.5
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**19.3**	14.3
Deferred Taxes	**5.1**	2.4
Changes in Current Assets and Liabilities:		
Accounts Receivable	**12.5**	1.7
Accrued Revenue	**22.9**	(2.0)
Accounts Payable	**(17.7)**	0.4
All other Current Assets and Liabilities	**(14.2)**	1.0
Deferred Regulatory and Other Charges	**(14.0)**	2.4
Other, net	**(1.5)**	0.4
Cash Provided by Operating Activities	**21.2**	27.1
Investing Activities:		
Property, Plant and Equipment Additions	**(43.0)**	(20.6)
Acquisition Costs	**(6.8)**	—
Cash (Used in) Investing Activities	**(49.8)**	(20.6)
Financing Activities:		
Proceeds From (Repayment of) Short-Term Debt, net	**(20.1)**	2.9
Dividends Paid	**(9.4)**	(6.1)
Proceeds from Issuance of Common Stock, net	**56.2**	0.7
Other, net	**(0.6)**	(3.6)
Cash Provided by (Used in) Financing Activities	**26.1**	(6.1)
Net Increase (Decrease) in Cash	**(2.5)**	0.4
Cash at Beginning of Period	**11.5**	4.6
Cash at End of Period	**$ 9.0**	$ 5.0
Supplemental Cash Flow Information:		
Interest Paid	**$ 11.6**	$ 8.0
Income Taxes Paid	**$ 0.6**	$ 0.5

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase Agreement (SPA) dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the "Acquisitions").

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern and central Maine and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the distribution utilities).

Granite State is a natural gas transportation pipeline, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third-party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service; Unitil Realty; and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and nine months ended September 30, 2009 are not necessarily indicative of results to be expected for the year ending December 31, 2009. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2008, as filed with the Securities and Exchange Commission (SEC) on February 18, 2008, for a description of the Company's Basis of Presentation.

As discussed above, the Company acquired Northern Utilities and Granite State on December 1, 2008. Accordingly, the operations of Northern Utilities and Granite State are included in the Company's consolidated financial statements from the date of acquisition, including the three and nine months ended September 30, 2009 but not for the three and nine months ended September 30, 2008. See Note 11.

As a result of the acquisitions of Northern Utilities and Granite State on December 1, 2008, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company expects that consolidated results of operations in future reporting periods will reflect to a greater degree the seasonal nature of natural gas sales by the acquired operating utilities. Accordingly, the Company expects that as a result of the acquisitions, consolidated results of operations will be positively affected during the first and fourth quarters, and negatively affected during the second and third quarters of future reporting years.

Derivatives – The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases NYMEX futures that correspond to the associated delivery month. Any gains or losses on the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. As a result of the ratemaking process, the Company records gains and losses as regulatory liabilities or assets and recognizes such gains or losses in Purchased Gas when recovered in revenues. The Company's Consolidated Balance Sheets include derivative liabilities related to net unrealized losses on current futures contracts of $3.6 million in Other Current Liabilities and on net unrealized gains on noncurrent futures contracts of $0.1 million in Noncurrent Liabilities at September 30, 2009. These amounts are offset in Accrued Revenues and Other Noncurrent Assets, respectively, on the Company's Consolidated Balance Sheets.

Reclassifications – Based on the Company's analysis certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation, principally including the reclassification of $22.4 million of Noncurrent Assets to Current Assets and $19.6 million of Noncurrent Liabilities to Current Liabilities related to current collections and obligations of Regulatory Assets and Regulatory Liabilities for 2008.

Recently Issued Pronouncements – In June 2009, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 168), a replacement of SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles". SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States. SFAS No. 168 is effective for financial statements for interim and annual periods ending after September 15, 2009. SFAS No. 168 establishes the FASB Accounting Standards Codification (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with Generally Accepted Accounting Principles. The purpose of the Codification is to simplify U.S. GAAP, without change, by consolidating the numerous accounting rules into logically organized topics. The Company has adopted SFAS No. 168 and therefore all references by the Company to authoritative accounting principles recognized by the FASB reflect the Codification.

In May 2009, the FASB issued FASB ASC 855, "Subsequent Events", (ASC 855) (originally issued as SFAS No.165, Subsequent Events), effective for interim and annual reporting periods ending after June 15, 2009. ASC 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company adopted ASC 855 and it did not have an impact on the Company's Consolidated Financial Statements. The Company evaluated all events or transactions that occurred after September 30, 2009 up through October 23, 2009. During this period no material subsequent events came to our attention.

On April 9, 2009, the FASB issued ASC 825, "Financial Instruments", (ASC 825) (originally issued as FASB Staff Position No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments".) ASC 825 requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. ASC 825 also requires those disclosures in summarized financial information at interim reporting periods. ASC 825 is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company has adopted ASC 825 and there was no impact on the Company's Consolidated Financial Statements. See Note 5 for relevant disclosures on the fair value of the Company's long-term debt.

On December 30, 2008, the FASB issued ASC 715, "Compensation – Retirement Benefits", (ASC 715) (originally issued as FASB Staff Position No. FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets") to provide guidance on an employers' disclosures about plan assets of a defined benefit pension or other postretirement plan. The disclosures about plan assets required by ASC 715 are to be provided for fiscal years ending after December 15, 2009. The Company does not expect that the adoption of ASC 715 will have an impact on the Company's Consolidated Financial Statements.

Note 2: Acquisitions

As discussed above, on December 1, 2008, the Company purchased (i) all of the outstanding capital stock of Northern Utilities from Bay State and (ii) all of the outstanding capital stock of Granite State from NiSource pursuant to the SPA dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil. The aggregate purchase price for the Acquisitions was $209.2 million, comprised of $160 million in cash, plus an additional working capital adjustment of $49.2 million. The largest component of working capital was approximately $30.0 million of natural gas storage inventory.

The Company accounted for the Acquisitions under the purchase method of accounting for business combinations, in accordance with FASB Statement No. 141, "Business Combinations" ("SFAS No. 141") and ASC 980-340, "Regulated Operations – Other Assets and Deferred Costs" (ASC 980-340). Accordingly, the Company recognized its estimate of the bargain purchase price (see "Plant Acquisition Adjustment" in the table below) at December 1, 2008. The process of valuing the assets, liabilities and transaction, transition and financing costs as a result of the Acquisitions was substantially completed in the second and third quarters of 2009. As a result, the Company has recognized adjustments to its original estimate of the Plant Acquisition Adjustment (PAA) in the second and third quarters of 2009.

The adjusted PAA is ($24.2 million), a decrease of $4.1 million from the original estimate of ($28.3 million). The adjusted Transaction and Transition Costs is an increase of $6.8 million over the original estimate, reflecting additional costs to complete the acquisition and financing. Partially offsetting the decrease in the PAA estimate due to the additional Transaction and Transition Costs were subsequent payments, cash settlements between the purchaser and seller and other post-closing adjustments reflecting changes to working capital and Net Utility Plant.

Table of Contents

The revised purchase price allocations are as follows:

Purchase Price Allocation
($ Millions)

	December 1, 2008
Equity Purchase Price	$ 160.0
Plus: Working Capital Adjustment	49.2
Aggregate Purchase Price	209.2
Transaction and Transition Costs	14.4
Total Cash Purchase Price	223.6
Allocation To:	
Book Value of Net Utility Plant	(197.0)
Cash Acquired	(6.9)
Accounts Receivable and Other Current Assets	(21.7)
Accrued Revenue	(7.0)
Gas Inventory	(32.3)
Regulatory and Other Noncurrent Assets	(34.2)
Accounts Payable and Other Current Liabilities	20.0
Regulatory Liabilities	31.3
Plant Acquisition Adjustment	**$ (24.2)**

In accordance with settlement agreements between the Company, the New Hampshire Public Utilities Commission (NHPUC) and the Maine Public Utilities Commission (MPUC) regarding the Acquisitions, the Company has agreed (i) not to seek recovery of transaction and transition costs in rates and (ii) for regulatory accounting purposes, to amortize, over a ten year period, the transaction and transition costs co-terminus with the Plant Acquisition Adjustment.

NOTE 3 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
09/23/09	11/16/09	11/02/09	$ 0.345
06/18/09	08/14/09	07/31/09	$ 0.345
03/26/09	05/15/09	05/01/09	$ 0.345
01/15/09	02/16/09	02/02/09	$ 0.345
09/25/08	10/31/08	10/17/08	$ 0.345
06/19/08	08/15/08	08/01/08	$ 0.345
03/20/08	05/15/08	05/01/08	$ 0.345
01/17/08	02/15/08	02/01/08	$ 0.345

NOTE 4 – COMMON STOCK AND PREFERRED STOCK

Common Stock

As of August 21, 2008 the Company's common stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's common stock trades under the symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 10,827,061, 5,781,025 and 7,791,617 of common shares outstanding at September 30, 2009, September 30, 2008 and December 31, 2008, respectively.

Unitil Corporation Common Stock Offerings – On May 27, 2009, the Company issued and sold 2,400,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2009 Offering). As part of the 2009 Offering, the Company granted the underwriters a 30-day option to purchase up to an additional 360,000 shares to cover any over-allotments. The underwriters exercised their over-allotment option and purchased an additional 300,000 shares of the Company's common stock in June 2009. The Company's net increase to Common Equity and Cash proceeds from the 2009 Offering, including the over-allotment were approximately $51.2 million (after payment of the underwriting discount, but excluding estimated offering expenses) and were used (i) to repay all amounts outstanding under the bridge credit facility (approximately $39.1 million) that the Company used to partially finance the acquisition of Northern Utilities and Granite State which closed on December 1, 2008, and related transaction costs and expenses and (ii) for other general corporate purposes, including capital contributions to Unitil's distribution utilities and repayment of short-term debt.

On December 15, 2008, the Company issued and sold 2,000,000 shares of its common stock at a price of $20.00 per share in a registered public offering (2008 Offering). The Company repaid $36.8 million outstanding under the bank financing facility for the Company's acquisitions of Northern Utilities and Granite State with the net proceeds from the sale and issuance of its common stock.

As part of the 2008 Offering, the Company granted the underwriters a 30-day option to purchase up to an additional 300,000 shares to cover any over-allotments. The underwriters exercised their over-allotment option and purchased an additional 270,000 shares of the Company's common stock in January 2009. The Company's net increase to Common Equity and Cash proceeds from the over-allotment sales were approximately $5.1 million (after payment of the underwriting discount, but excluding estimated offering expenses) and were used to repay a portion of the bank financing for the Company's acquisitions of Northern Utilities and Granite State and to repay other short-term indebtedness. The Company recorded the issuance of the 270,000 shares, the sale proceeds and the increase in Common Equity in January 2009.

Dividend Reinvestment and Stock Purchase Plan – During the first nine months of 2009, the Company sold 33,184 shares of its Common Stock, at an average price of $20.88 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $693,000 were used to reduce short-term borrowings.

During the first nine months of 2008, the Company sold 22,462 shares of its Common Stock, at an average price of $27.43 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $616,000 were used to reduce short-term borrowings.

Restricted Stock Plan – The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 17, 2009, 32,260 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $661,007. Compensation expense associated with shares issued under the Plan is recognized ratably as the shares vest and was $0.4 million and $0.4 million for the nine months ended September 30, 2009 and 2008, respectively. At September 30, 2009, there was approximately $1.2 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 2.9 years as the shares vest. During the nine months ended September 30, 2009, 12,459 restricted shares vested. As of September 30, 2009 there were 52,019 unvested restricted shares.

Preferred Stock

Details on preferred stock at September 30, 2009, September 30, 2008 and December 31, 2008 are shown below:

(Amounts in Millions)

	September 30,		December 31,
	2009	2008	2008
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	$ 0.2	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	0.8	0.8	0.8
8.00% Series, $100 Par Value	1.0	1.0	1.0
Total Preferred Stock	$ 2.0	$ 2.0	$ 2.0

Table of Contents

NOTE 5 – LONG-TERM DEBT, CREDIT ARRANGEMENTS AND GUARANTEES

Long-Term Debt

Details on long-term debt at September 30, 2009, September 30, 2008 and December 31, 2008 are shown below ($ Millions):

	September 30, 2009	September 30, 2008	December 31, 2008
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Northern Utilities Senior Notes:			
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	—	30.0
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	—	50.0
Granite State Senior Notes:			
7.15% Senior Notes, Due December 15, 2018	**10.0**	—	10.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due Through August 1, 2017	**4.4**	4.8	4.7
Total Long-Term Debt	**249.4**	159.8	249.7
Less: Current Portion	**0.4**	0.4	0.4
Total Long-term Debt, Less Current Portion	**$ 249.0**	$ 159.4	$ 249.3

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield for September 2009. The carrying value of the Company's long-term debt at September 30, 2009 is $249.4 million. The fair value of the Company's long-term debt at September 30, 2009 is estimated to be approximately $275.6 million. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

On December 3, 2008, Northern Utilities completed the sale of $80 million of Senior Unsecured Notes, through a private placement to institutional investors. The debt financing included $50 million of 30-year notes with a coupon rate of 7.72% and $30 million of 10-year notes with a coupon rate of 6.95%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Northern Utilities.

On December 15, 2008, Granite State completed the sale of $10 million of Senior Unsecured Notes, through a private placement to institutional investors. The Notes have a term of 10 years maturity and a coupon rate of 7.15%. The Company used the proceeds from the long-term Note financing to repay a portion of the bank financing for Unitil's acquisition of Granite State.

Credit Arrangements

At September 30, 2009, the Company had $54.0 million in short-term debt outstanding through bank borrowings under its revolving credit agreement. The revolving credit agreement contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of September 30, 2009, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 13, 2009, the Company entered into an amendment to its 364-day revolving credit facility with Bank of America, as administrative agent, and a syndicate of lenders. The Company originally entered into the facility on November 26, 2008. The amendment increases the maximum borrowings under the facility from $60 million to $80 million. It also (i) decreases the upfront fees to 15 basis points of the aggregate commitment, (ii) changes the commitment fees from 30 to 40 basis points per annum of the average difference between the aggregate commitment and the outstanding borrowings, (iii) changes the margin applicable to borrowings from 1.75% to 2.0% per annum, and (iv) extends the maturity date for borrowings to October 12, 2010. Except as expressly amended by the amendment, all other terms and conditions of the facility remain in full force and effect.

On November 1, 2008, Northern Utilities entered into a gas storage management agreement pursuant to which (i) Northern Utilities released certain pipeline and storage capacity to an asset manager from November 1, 2008 through April 30, 2009 and (ii) the asset manager financed inventories associated with the released storage capacity from Northern Utilities contemporaneously with the closing of the Acquisitions. Pursuant to the agreement, Northern Utilities repurchased the storage inventory over the course of the 2008/2009 winter heating season at the same price initially paid by the asset manager. Effective May 1, 2009, Northern entered into a subsequent gas storage management agreement which provides for refilling the storage inventory between May 1, 2009 and October 31, 2009. Similar to the prior agreement, the asset manager is maintaining the cost of the inventory. On October 31, 2009, at the end of the refill period, Northern will purchase the inventory associated with this storage asset. Northern has entered into a further asset management arrangement, which becomes effective November 1, 2009, under which Northern will release certain pipeline and storage assets and resell the storage inventory to an asset manager and subsequently repurchase the inventory over the course of the 2009/2010 winter heating season at the same price at which it sold the inventory to the asset manager. There was $7.6 million and $24.0 million outstanding at September 30, 2009 and December 31, 2008, respectively, related to these agreements.

Guarantees

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2009 there are $21.3 million of guarantees outstanding and the longest of these guarantees extends through December 31, 2010. These guarantees are not required to be recorded under the provisions of ASC 460, "Guarantees."

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of September 30, 2009, the principal amount outstanding for the 8% Unitil Realty notes was $4.4 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite State notes due 2018. As of September 30, 2009, the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. This guarantee will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Table of Contents

NOTE 6 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and nine months ended September 30, 2009 and September 30, 2009 (Millions):

Three Months Ended:	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
September 30, 2009					
Revenues	**$ 54.2**	**$ 15.2**	**$ —**	**$ 1.0**	**$ 70.4**
Segment Profit (Loss)	**1.9**	**(2.9)**	**—**	**0.4**	**(0.6)**
Capital Expenditures	**6.1**	**10.1**	**0.7**	**—**	**16.9**
September 30, 2008					
Revenues	$ 63.6	$ 4.4	$ —	$ 1.1	$ 69.1
Segment Profit (Loss)	1.9	(0.6)	—	0.2	1.5
Capital Expenditures	6.3	2.6	1.5	—	10.4
Nine Months Ended:					
September 30, 2009					
Revenues	**$ 163.3**	**$ 111.0**	**$ —**	**$ 3.2**	**$ 277.5**
Segment Profit (Loss)	**3.2**	**4.2**	**0.1**	**1.2**	**8.7**
Capital Expenditures	**21.2**	**21.0**	**0.8**	**—**	**43.0**
Segment Assets	**347.9**	**352.6**	**10.7**	**—**	**711.2**
September 30, 2008					
Revenues	$ 172.2	$ 25.3	$ —	$ 2.9	$ 200.4
Segment Profit (Loss)	4.4	1.9	(0.2)	0.3	6.4
Capital Expenditures	15.9	3.1	1.6	—	20.6
Segment Assets	344.9	104.8	17.1	0.7	467.5

NOTE 7 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2008 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 18, 2009.

Legal Proceedings

A putative class action Complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009 an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Table of Contents

Regulatory Matters

Major Ice Storm – On December 11 and 12, 2008, a severe ice storm struck the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including all of Unitil's 28,000 Massachusetts customers, and approximately half of its New Hampshire customers. Fitchburg was able to restore power to one-third of its Massachusetts customers within three days, 80 percent of its customers by day seven, and the final Massachusetts customers, including those with individual service problems, were restored by December 24, 2008. On January 7, 2009, the MDPU opened an investigation into the preparation and response of the Massachusetts electric distribution companies to the December 12, 2008 Winter Storm. Evidentiary hearings before the MDPU concerning Fitchburg's storm response were held in May, 2009. After the hearing, the Massachusetts Attorney General recommended that the MDPU assess fines against Fitchburg totaling $4.65 million as penalties for Fitchburg's performance during and after the storm. Fitchburg has argued that the Attorney General's recommendation is not supported by the evidence, is contrary to the record of the Company's actual performance, and incorrectly interprets the authority of the MDPU to assess such penalties. A decision by the MDPU regarding the results of its investigation and the recommendation of the Attorney General remains pending.

As a result of the ice storm, the Company has spent approximately $20 million for the repair and replacement of electric distribution systems damaged during the storm, including $5.9 million related to capital construction and $14.1 million which has been deferred as a regulatory asset. Fitchburg and UES have filed petitions with their respective regulatory commissions, the MDPU and the NHPUC, requesting accounting orders to allow each to defer for future recovery in rates the costs associated with the emergency repair of its electric distribution system for damage caused by the ice storm. These petitions remain pending. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in future regulatory proceedings. Also, the Company has spent $2.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. While the Company cannot determine the ultimate outcome of the proceedings discussed above, the Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

Fitchburg – Electric Division – On November 26, 2008, Fitchburg submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan (the Annual Reconciliation Filing). The rates were approved effective January 1, 2009, subject to reconciliation pursuant to the MDPU's investigation. This matter remains pending before the MDPU.

Fitchburg – Gas Operations – On March 12, 2009, the MDPU opened an investigation into Fitchburg's gas procurement practices. The purpose of this investigation is to determine: (1) whether Fitchburg has engaged in a purchasing program to mitigate the volatility of gas commodity prices without MDPU approval; and, if so, (2) an appropriate remedy, including whether Fitchburg's ratepayers are entitled to reimbursement for any gas supply costs that are higher than they would have been absent such purchasing program. The Company believes that its gas procurement practices have been and remain in compliance and consistent with all relevant MDPU rules and orders and Massachusetts law, and does not believe that the investigation will have a material adverse impact upon the Company's financial condition or the results of its operations. Evidentiary hearings were concluded in June 2009. The Massachusetts Attorney General, an intervener in the MDPU investigation, has argued that Fitchburg was required to obtain MDPU approval of its gas purchasing program, and has recommended that Fitchburg refund to ratepayers $863,368 of gas supply costs. Fitchburg disagrees with the Attorney General's analysis and conclusions and believes that the refund recommendation is without precedent and contrary to the evidence. A decision by the MDPU remains pending.

Fitchburg – Other – On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, and special tariffs to allow the net metering of customer-owned renewable generation. These matters, under review in separately designated dockets, remain pending.

Unitil Energy – On June 17, 2009, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2009, including reconciliation of prior year costs and revenues. UES filed revisions on July 14, 2009. On July 24, 2009, the NHPUC approved the reconciliation filing and rates effective August 1, 2009.

Northern Utilities – Notices of Probable Violation – Beginning in October 2007, the MPUC initiated formal investigations into a number of Notices of Probable Violation (NOPVs) alleging that Northern Utilities had violated various provisions of the federal pipeline safety regulations, as adopted by the MPUC. Northern Utilities, the MPUC Staff and Unitil filed a comprehensive settlement (Settlement), which was approved by the MPUC on November 21, 2008, resolving these matters. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for certain safety related improvements for which no rate recovery will be allowed and obligations to be undertaken for Northern Utilities' distribution system to ensure compliance with the relevant state and federal gas safety laws. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at September 30, 2009 was $2.3 million.

Northern Utilities – New Hampshire 2007/2008 Winter Cost of Gas – On October 31, 2007, the NHPUC issued Order No. 24,798 concerning the 2007/2008 winter cost of gas proceeding for Northern Utilities' New Hampshire division. In that order, the NHPUC noted that Northern Utilities had identified an unusually high level of lost and unaccounted for gas (UAFG), and ordered Northern Utilities to file a detailed report concerning its investigation of this matter. Through its investigation, Northern Utilities determined that the UAFG affected both its New Hampshire and Maine divisions, and that the cause appeared to be incorrect metering at the Maritimes & Northeast (M&NE) / Portland Natural Gas Transmission System's (PNGTS) Newington Gate Station caused by an erroneous meter module change. The metering equipment was operated and maintained by a third party, Spectra Energy, the parent company of M&NE. PNGTS and M&NE share joint ownership of the section of the pipeline connected to Granite State at the Newington Gate Station. The error caused Granite State to be billed for 758,702 Dth of natural gas, with Granite State then billing Northern Utilities for an equivalent amount, although the volumes of gas were not actually delivered. The meter error was corrected and Northern Utilities, Granite State, Spectra Energy and PNGTS reached an agreement whereby PNGTS will provide to Northern Utilities, through Granite State, gas volumes equal to the misread amounts to correct for the error, over a period of approximately 18 months. Both the NHPUC and the MPUC have approved this arrangement, as well as Northern Utilities' methodology for allocating the gas received to its Maine and New Hampshire divisions based upon the actual gas use over the period the meters were misread. As of September 30, 2009, Northern Utilities has recorded approximately $0.7 million reflecting the anticipated liability of the future refund amount based on current market prices, with an offsetting receivable from Granite State, and Granite State has recorded a receivable from PNGTS for this amount.

Northern Utilities – Maine Capacity Costs – In its October 28, 2008 approval of Northern Utilities' Maine Division's Cost of Gas Factor for the 2008-2009 Winter Period, the MPUC approved recovery of an additional $0.5 million of annual demand costs that had been inadvertently omitted from Northern Utilities' reconciliation of the 2008-2009 Winter Period rates, although analogous costs had been included in its calculation of 2007-2008 Winter Period rates. The MPUC determined that recovery of these Local Production Capacity Costs was consistent with previous MPUC orders and the $0.5 million was recovered in Northern Utilities' rates in Maine between November 1, 2008 and April 30, 2009.

Northern Utilities also reported that, upon investigation, these annual demand costs, though approved, were incorrectly excluded from its reconciliation for five previous annual periods. The total impact for the five years is $2.4 million. On November 7, 2008, Northern Utilities, prior to the completion of the acquisition by Unitil, filed a request with the MPUC seeking an accounting order allowing it to defer and amortize for recovery these unrecovered gas costs over a three year period. In its Order dated July 1, 2009, the MPUC denied Northern's request for an accounting order and denied Northern's recovery of the unrecovered annual demand gas costs in future rates. Based on the uncertainty of the outcome of this proceeding, the Company had not recorded a regulatory asset related to this matter and therefore the MPUC's Order does not adversely impact the Company's financial statements.

NOTE 8 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2008 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 18, 2009.

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of September 30, 2009, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at September 30, 2009 are current and non-current accrued liabilities totaling $10.3 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties. Also included on the Company's Consolidated Balance Sheet at September 30, 2009 are current and non-current accrued liabilities totaling $2.4 million associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the recovery of these environmental remediation costs is probable through the regulatory process.

NOTE 9: RETIREMENT BENEFIT OBLIGATIONS

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service. In September 2009, the Company amended the Pension Plan as follows:
  - The Pension Plan will be closed to non-union employees who are hired on or after January 1, 2010.
  - All non-union employees hired before January 1, 2010 will have a choice of either:
    - Remaining in the Pension Plan with the current set of benefits. Non-union employees who elect this option will experience no changes in their pension benefits.

    or

    - Electing to move to Unitil Corporation's enhanced Tax Deferred Savings and Investment Plan. Non-union employees who elect this option will receive a frozen benefit from the existing Pension Plan for all of the benefits that they have accrued to December 31, 2008. This frozen benefit will not grow with future salary increases or

Table of Contents

future service. Non-union employees who elect this option will receive an enhanced employer matching contribution as well as a Company contribution in the Unitil Corporation Tax Deferred Savings and Investment Plan.

- Union employees were not affected by this amendment.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) – The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.
- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) – The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

	2009	2008
Used to Determine Plan Costs		
Discount Rate	**6.25%**	6.00%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017
	2009	**2008**
Used to Determine Benefit Obligations:		
Discount Rate	**6.25%**	6.00%
Rate of Compensation Increase	**3.50%**	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2017

Table of Contents

The following tables provide the components of the Company's Retirement plan costs ($000's):

Three Months Ended September 30,	Pension Plan 2009	Pension Plan 2008	PBOP Plan 2009	PBOP Plan 2008	SERP 2009	SERP 2008
Service Cost	**$ 571**	$ 488	**$ 357**	$ 355	**$ 54**	$ 37
Interest Cost	**1,073**	944	**578**	559	**46**	31
Expected Return on Plan Assets	**(1,108)**	(1,093)	**(89)**	(82)	**—**	—
Prior Service Cost Amortization	**66**	27	**428**	341	**—**	1
Transition Obligation Amortization	**—**	—	**5**	6	**—**	—
Actuarial Loss Amortization	**399**	318	**—**	—	**17**	6
Sub-total	**1,001**	684	**1,279**	1,179	**117**	75
Amounts Capitalized and Deferred	**(388)**	(226)	**(486)**	(496)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 613**	$ 458	**$ 793**	$ 683	**$ 117**	$ 75

Nine Months Ended September 30,	Pension Plan 2009	Pension Plan 2008	PBOP Plan 2009	PBOP Plan 2008	SERP 2009	SERP 2008
Service Cost	**$ 1,713**	$ 1,464	**$ 1,071**	$ 1,065	**$ 162**	$ 111
Interest Cost	**3,220**	2,831	**1,735**	1,677	**136**	94
Expected Return on Plan Assets	**(3,324)**	(3,280)	**(267)**	(245)	**—**	—
Prior Service Cost Amortization	**198**	81	**1,284**	1,022	**(1)**	1
Transition Obligation Amortization	**—**	—	**15**	17	**—**	—
Actuarial Loss Amortization	**1,197**	956	**—**	—	**53**	18
Sub-total	**3,004**	2,052	**3,838**	3,536	**350**	224
Amounts Capitalized and Deferred	**(1,034)**	(673)	**(1,286)**	(1,448)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 1,970**	$ 1,379	**$ 2,552**	$ 2,088	**$ 350**	$ 224

Employer Contributions

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. As of September 30, 2009, the Company had contributed approximately $4.2 million to fund its Pension Plan in 2009 and does not expect to make any additional contributions in 2009.

As of September 30, 2009, the Company had made $1.1 million and $40,000 of contributions to the PBOP and SERP Plans, respectively, in 2009. The Company presently anticipates contributing an additional $1.7 million and $13,000 to the PBOP and SERP Plans, respectively, in 2009.

NOTE 10: INCOME TAXES

The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2008 and for the current interim reporting period ended September 30, 2009 in accordance with ASC 740-25, "Income Taxes – Recognition", (ASC 740-25), and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by ASC 740-25 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2006; December 31, 2007; and December 31, 2008. Income tax filings for the year ended December 31, 2008 have been filed with the Internal Revenue Service. In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized net operating loss (NOL) carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of $5.0 million and $6.7 million, respectively. These NOL carrybacks result in a refund to the Company of $4.0 million. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

NOTE 11: UNAUDITED PRO FORMA FINANCIAL DATA RELATED TO ACQUISITIONS

On December 1, 2008, the Company acquired Northern Utilities and Granite State, as discussed in Note 1. Had the results of operations for Northern Utilities and Granite State been combined with the Company as of the beginning of 2008, the Company's pro forma results for the three and nine months ended September 30, 2008 would have been as follows:

(Millions, except per share amounts) (Unaudited)	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
Revenues	$ 82.0	$ 288.1
Earnings (Loss) Applicable to Common Shareholders	$ (2.1)	$ 5.0
Earnings (Loss) per Share		
Basic	$ (0.20)	$ 0.47
Diluted	$ (0.20)	$ 0.47

The Unaudited Pro Forma Financial Data include non-recurring charges to operating expenses of $0.8 million and $2.0 million, after tax, in the three and nine months ended September 30, 2008, respectively, related to compliance violation penalties incurred by Northern Utilities.

The Unaudited Pro Forma Financial Data are presented for illustrative purposes only and do not indicate the financial results of the combined companies had the companies actually been combined and had the impact of possible revenue enhancements and expense efficiencies, among other factors, been considered, and is not intended to be a projection of future results.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief

Table of Contents

Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in the Company's internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 7 and 8 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2008 as filed with the SEC on February 18, 2009.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended September 30, 2009.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), adopted by the Company on March 26, 2009, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases; however, the trading plan will terminate when $83,000 in value of shares have been purchased or, if sooner, on March 26, 2010.

The Company's repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
7/1/09 – 7/31/09	—	—	—
8/1/09 – 8/31/09	—	—	—
9/1/09 – 9/30/09	251	$ 21.86	251
Total	251	$ 21.86	251

Table of Contents

Item 5. Other Information

On October 23, 2009, the Company issued a press release announcing its results of operations for the three- and nine-month periods ended September 30, 2009. The press release is furnished with this Quarterly Report on Form 10-Q as Exhibit 99.1.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Weighted Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated October 23, 2009 Announcing Earnings For the Quarter Ended September 30, 2009.	Filed herewith

[Table of Contents](#)

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	UNITIL CORPORATION
	(Registrant)
Date: October 23, 2009	/s/ Mark H. Collin
	Mark H. Collin Chief Financial Officer
Date: October 23, 2009	/s/ Laurence M. Brock
	Laurence M. Brock Chief Accounting Officer

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Weighted Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated October 23, 2009 Announcing Earnings For the Quarter Ended September 30, 2009.	Filed herewith

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER WEIGHTED AVERAGE COMMON SHARE OUTSTANDING
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net Income (Loss)	**$ (0.6)**	$ 1.5	**$ 8.8**	$ 6.5
Less: Dividend Requirements on Preferred Stock	**—**	—	**0.1**	0.1
Net Income Applicable to Common Stock	**$ (0.6)**	$ 1.5	**$ 8.7**	$ 6.4
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**10,767**	5,745	**9,267**	5,733
Dilutive Effect of Stock Options and Restricted Stock (000's)	**—**	3	**—**	5
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**10,767**	5,748	**9,267**	5,738
Earnings Per Share – Basic	**($0.06)**	$ 0.27	**$ 0.94**	$ 1.12
Earnings Per Share – Diluted	**($0.06)**	$ 0.27	**$ 0.94**	$ 1.12

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 23, 2009
/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 23, 2009
/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 23, 2009
/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	October 23, 2009
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	October 23, 2009
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	October 23, 2009

Exhibit 99.1

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports Third Quarter Results

Hampton, NH – October 23, 2009: Unitil Corporation (NYSE: UTL) (www.unitil.com) today announced a net loss of ($0.6) million for the third quarter of 2009, compared to earnings of $1.5 million for the third quarter of 2008. Earnings (loss) per common share (EPS) were ($0.06) for the three months ended September 30, 2009 compared with $0.27 in the third quarter of 2008. For the nine months ended September 30, 2009, the Company reported net income of $8.7 million, an increase of $2.3 million over the same period of 2008 reflecting the acquisitions of Northern Utilities, Inc. (Northern Utilities) and Granite State Gas Transmission, Inc. (Granite State) on December 1, 2008. EPS for the nine months ended September 30 were $0.94 for 2009 compared to $1.12 for 2008, reflecting a higher number of average shares outstanding year over year, discussed below.

"We continue to see the positive impact of our acquisition of Northern Utilities and the Granite State pipeline on our utility operations," said Robert G. Schoenberger, Unitil's Chairman and Chief Executive Officer. "In these challenging economic times, we are pleased to pass on the benefit of significantly lower energy costs to our customers. We are committed to aggressively manage our costs and to make prudent investments in our system for the benefit of our customers and shareholders."

As a result of the acquisitions of Northern Utilities and Granite State, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the acquisitions are fully reflected in both reporting periods. In particular, the Company's results will reflect the seasonal nature of the natural gas business. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Between December 2008 and June 2009, the Company sold 4,970,000 shares of its common stock at a price of $20.00 per share in registered public offerings. The Company used the net proceeds of $93.1 million from these offerings to finance the acquisition of Northern Utilities and Granite State and for capital contributions to Unitil's other distribution utilities and the repayment of short-term debt. Overall, the results of operations and net income are reflected over a higher number of average shares outstanding year over year.

Earnings in the third quarter reflect higher gas utility sales margins offset by higher operating, depreciation and interest costs in the quarter as well as a higher number of average shares outstanding year over year, discussed above. Natural gas sales margin increased $5.9 million and $32.4 million in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. These increases primarily reflect the contribution by Northern Utilities, the Company's recently acquired local gas distribution utility. Natural gas sales in the nine month period ended September 30, 2009 reflect a colder winter heating season this year. Average winter temperatures in the Company's service territories were 6.4% colder than last year.

Electric sales margin increased $0.2 million in the three months ended September 30, 2009 compared to the same period in 2008, reflecting higher rates offset by lower sales. For the nine months ended September 30, 2009, electric sales margin decreased $0.1 million, compared to the same period in 2008, reflecting lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 4.5% and 5.3% in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008 due to lower average usage by our customers reflecting the continued regional economic slowdown and milder summer weather in 2009.

Selected Financial Data for 2009 is presented in the following table:

Unitil Corporation – Condensed Financial Data

(Millions, except Per Share data) (unaudited)

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2009	**2008**	**Change**	**2009**	**2008**	**Change**
Gas Therm Sales: (a)						
Residential	2.9	0.7	314.3%	29.1	7.7	277.9%
Commercial/Industrial	19.5	3.0	550.0%	106.1	13.9	663.3%
Total Gas Therm Sales	**22.4**	**3.7**	**505.4%**	**135.2**	**21.6**	**525.9%**
Electric kWh Sales:						
Residential	172.1	176.3	(2.4%)	493.8	506.2	(2.4%)
Commercial/Industrial	263.0	279.4	(5.9%)	738.3	794.5	(7.1%)
Total Electric kWh Sales	**435.1**	**455.7**	**(4.5%)**	**1,232.1**	**1,300.7**	**(5.3%)**
(a) 2009 Gas Therm Sales include Northern Utilities, Inc., acquired on December 1, 2008.						
Gas Revenues	$ 15.2	$ 4.4	$ 10.8	$ 111.0	$ 25.3	$ 85.7
Purchased Gas	7.3	2.4	4.9	68.7	15.4	53.3
Gas Sales Margin	**7.9**	**2.0**	**5.9**	**42.3**	**9.9**	**32.4**
Electric Revenues	54.2	63.6	(9.4)	163.3	172.2	(8.9)
Purchased Electricity	39.7	49.3	(9.6)	121.6	130.4	(8.8)
Electric Sales Margin	**14.5**	**14.3**	**0.2**	**41.7**	**41.8**	**(0.1)**
Usource Sales Margin	**1.0**	**1.1**	**(0.1)**	**3.2**	**2.9**	**0.3**
Total Sales Margin:	**23.4**	**17.4**	**6.0**	**87.2**	**54.6**	**32.6**
Operation & Maintenance Expenses	12.0	7.0	5.0	34.4	18.7	15.7
Depreciation, Amortization, Taxes & Other	8.0	6.5	1.5	31.6	22.2	9.4
Interest Expense, Net	4.0	2.4	1.6	12.5	7.3	5.2
Earnings (Loss) Applicable to Common Shareholders:	**$ (0.6)**	**$ 1.5**	**$ (2.1)**	**$ 8.7**	**$ 6.4**	**$ 2.3**
Earnings Per Share	**$ (0.06)**	**$ 0.27**	**$ (0.33)**	**$ 0.94**	**$ 1.12**	**$ (0.18)**

Operation & Maintenance (O&M) expenses increased $5.0 million and $15.7 million for the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. The addition of Northern Utilities and Granite State to consolidated operating results in 2009 accounted for $7.7 million of the increase in the nine month period. For the nine month period, in addition to the increases due to the acquisition of Northern Utilities and Granite State, higher professional fees expense of $2.3 million, including $2.0 million of costs related to the December 2008 ice storm, higher compensation and employee benefit expenses of $1.3 million and higher utility operating costs of $1.6 million contributed to the increase in O&M expenses. The increase in O&M expenses for the nine month period also reflects higher insurance costs in 2009 compared to the same period in 2008, due to the receipt of a $2.8 million insurance settlement in 2008.

Depreciation, Amortization, Taxes and Other expenses increased $1.5 million and $9.4 million in the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. The increases primarily reflect the addition of Northern Utilities and Granite State to consolidated operating results in 2009, and higher depreciation on normal utility plant additions partially offset by lower amortization on natural gas inventory carrying costs and lower income taxes on lower pre-tax earnings for the three month period.

Interest Expense, Net increased $1.6 million and $5.2 million in the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2009. These increases are primarily due to the addition of Northern Utilities and Granite State, reflecting the issuance of long-term notes by Northern Utilities and Granite State in December 2008. In addition, these increases in Interest Expense, Net reflect higher average borrowings in the current periods.

Also in the third quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

About Unitil

Unitil is a public utility holding company with subsidiaries providing electric and natural gas distribution service in New Hampshire and Massachusetts, natural gas distribution service in Maine and energy services throughout the northeast. Unitil serves approximately 170,000 utility customers in three states. Its utility affiliates include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc. and Granite State Gas Transmission, Inc. Its other subsidiaries include Unitil Service Corp. and its non-regulated business segment doing business as Usource.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended March 31, 2010

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire **(State or other jurisdiction of incorporation or organization)**	**02-0381573** **(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire **(Address of principal executive office)**	**03842-1720** **(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 26, 2010
Common Stock, No par value	**10,859,918 Shares**

[Table of Contents](#)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended March 31, 2010

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource.

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy, which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,500 electric customers and 70,000 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite State, a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and, combined with Granite State, had an investment in Net Utility Plant of $455.1 million at March 31, 2010. Unitil's total operating revenue includes revenue to recover the approved cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not affected by changes in the cost of purchased electricity and natural gas. Earnings from Unitil's utility operations are derived from the return on investment in the three distribution utilities and Granite.

Unitil also conducts non-regulated operations principally through Usource, which is wholly-owned by Unitil Resources. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. The Company's other subsidiaries include Unitil Service, which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, and Unitil Realty, which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

RATES AND REGULATION

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, in regards to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC); Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and the Maine Public Utilities Commission (MPUC). Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party suppliers. A majority of Unitil's largest commercial and industrial (C&I) customers purchase their electric and natural gas supplies from third party suppliers. However, most residential and small customers continue to purchase their electric and natural gas supplies through Unitil's distribution utilities. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features. For additional discussion, please refer to Unitil's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 10, 2010.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- The Company's ability to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Recovery of deferred major storm costs;
- Recovery of energy commodity costs;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;

- Interest rate fluctuation and credit market concerns;
- General economic conditions that could have an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of our counterparty obligations, including those of our insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

SUBSEQUENT EVENT

On April 15, 2010 Unitil Energy filed a proposed base rate increase of $10.1 million, which represents an increase of 6.5 percent above present rates. Unitil Energy requested temporary rates to be effective July 1, 2010. In addition, Unitil Energy requested adjustments for a Rate Year Step Adjustment, a Large Capital Project Step Adjustment and a long-term rate plan establishing step adjustments associated with the Company's Reliability Enhancement Plan and Vegetation Management Plan. A decision from the NHPUC on Unitil Energy's rate increase request may take up to one year.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended March 31, 2010 and March 31, 2009 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Part I, Item 1 of this report.

As a result of the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders was $6.5 million for the first quarter of 2010 compared to 2009 first quarter earnings of $9.1 million. Earnings per common share (EPS) were $0.61 for the three months ended March 31, 2010 compared to EPS of $1.14 in the first quarter of 2009. Earnings per share in the first quarter of 2010 are not directly comparable with 2009 due to a 35% increase in average common shares outstanding year over year resulting from the issuance of new common equity in 2009 to complete the financing of the Company's acquisition of Northern Utilities and Granite State.

Natural gas sales margin decreased $1.4 million in the three months ended March 31, 2010 compared to the same period in 2009 reflecting lower sales volumes. Total therm sales of natural gas decreased 6.5% in the three months ended March 31, 2010 compared to the same period in 2009, reflecting decreases of 7.8% and 6.0% in sales to residential and commercial and industrial (C&I) customers, respectively. The lower sales in the first three months of 2010 reflect a milder winter heating season this year. There were 7.6% fewer Heating Degree Days in the Company's service territories in the first quarter of 2010 compared to the same period in 2009. On a weather-normalized basis, natural gas sales decreased by 2.7% in the three months ended March 31, 2010 compared to the same period in 2009.

Electric sales margin decreased $0.3 million in the three months ended March 31, 2010 compared to the same period in 2009, reflecting lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 1.8% in the three months ended March 31, 2010 compared to the same period in 2009 driven by lower average usage per customer reflecting the milder winter weather as well as energy conservation efforts by our customers. On a weather-normalized basis, kWh sales in the three months ended March 31, 2010 were flat compared to the same period in 2009.

Operation & Maintenance (O&M) expenses increased $1.8 million in the three months ended March 31, 2010 compared to the same period in 2009. The increase in O&M expenses primarily reflects higher utility operating costs associated with the completion of the transition and full integration of Northern Utilities and Granite State operations into the Company's consolidated operating results in the current period.

Depreciation, Amortization, Taxes and Other expenses decreased $0.4 million in the three months ended March 31, 2010 compared to the same period in 2009. Higher depreciation expense on utility plant additions were offset by lower amortization and lower income taxes on lower pre-tax earnings in the quarter.

Interest Expense, Net decreased $0.5 million in the three months ended March 31, 2010 compared to the same period in 2009 reflecting higher acquisition related debt fees incurred in 2009 and lower average borrowings in the current quarter.

Usource, our non-regulated energy brokering business, recorded revenues of $1.1 million in the first quarter of 2010, unchanged when compared to the first quarter of 2009. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

Additionally, EPS in the first quarter of 2010 reflect a higher number of average shares outstanding year over year. In May and June 2009, the Company sold 2,700,000 shares of its common stock at a price of $20.00 per share in a registered public offering. The Company used the net proceeds of $51.2 million from this offering to complete the acquisition of Northern Utilities and Granite State.

In 2009, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2010 and March, 2010 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three months ended March 31, 2010.

Gas Sales, Revenues and Margin

Therm Sales – Unitil's total therm sales of natural gas decreased 6.5% in the three months ended March 31, 2010 compared to the same period in 2009, reflecting decreases of 7.8% and 6.0% in sales to residential and C&I customers, respectively. The lower sales in the first three months of 2010 reflect a milder winter heating season this year. There were 7.6% fewer Heating Degree Days in the Company's service territories in the first quarter of 2010 compared to the same period in 2009. On a weather-normalized basis, natural gas sales decreased by 2.7% in the three months ended March 31, 2010 compared to the same period in 2009.

Table of Contents

The following table details total firm therm sales for the three months ended March 31, 2010 and 2009, by major customer class:

Therm Sales (millions)

	Three Months Ended March 31,			
	2010	**2009**	**Change**	**% Change**
Residential	**17.8**	19.3	(1.5)	(7.8%)
Commercial/Industrial	**54.6**	58.1	(3.5)	(6.0%)
Total	**72.4**	77.4	(5.0)	(6.5%)

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three months ended March 31, 2010 and 2009:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended March 31,			
	2010	**2009**	**$ Change**	**% Change(1)**
Gas Operating Revenue:				
Residential	**$ 25.8**	$ 30.4	$ (4.6)	(6.4%)
Commercial / Industrial	**35.3**	42.0	(6.7)	(9.2%)
Total Gas Operating Revenue	**$ 61.1**	$ 72.4	$ (11.3)	(15.6%)
Cost of Gas Sales:				
Purchased Gas	**$ 38.3**	$ 48.4	$ (10.1)	(14.0%)
Conservation & Load Management	**0.8**	0.6	0.2	0.3%
Gas Sales Margin	**$ 22.0**	$ 23.4	$ (1.4)	(1.9%)

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues decreased $11.3 million, or 15.6%, in the three months ended March 31, 2010 compared to the same period in 2009. Total Gas Operating Revenues include the recovery of the approved cost of sales, which are recorded as Purchased Gas and Conservation & Load Management (C&LM) in Operating Expenses. The decrease in Total Gas Operating Revenues in the first quarter of 2010 reflects lower Purchased Gas costs of $10.1 million and lower gas sales margin of $1.4 million, partially offset by higher C&LM revenues of $0.2 million.

The Purchased Gas and C&LM component of Gas Operating Revenues decreased $9.9 million, or 13.7%, in the three months ended March 31, 2010 compared to the same period in 2009. The decrease reflects lower natural gas commodity prices and the lower sales of natural gas, discussed above. Purchased Gas revenues include the recovery of the approved cost of gas supply as well as other energy supply related costs. C&LM revenues include the recovery of the approved cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin decreased $1.4 million in the three months ended March 31, 2010 compared to the same period in 2009. This decrease was driven by the lower sales of natural gas, discussed above.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – In the first quarter of 2010, Unitil's total electric kWh sales decreased 1.8% compared to the first quarter of 2009. Sales to residential and C&I customers decreased 1.6% and 1.9%, respectively, in the first quarter of 2010 compared to the same period in 2009. The lower kWh sales in 2010 compared to 2009 were primarily driven by lower average usage per customer reflecting the milder winter weather as well as energy conservation efforts by our customers. On a weather-normalized basis, kWh sales in the three months ended March 31, 2010 were flat compared to the same period in 2009.

The following table details total kWh sales for the three months ended March 31, 2010 and 2009 by major customer class:

kWh Sales (millions)

	Three Months Ended March 31,			
	2010	2009	Change	% Change
Residential	**177.7**	180.6	(2.9)	(1.6%)
Commercial/Industrial	**237.5**	242.1	(4.6)	(1.9%)
Total	**415.2**	422.7	(7.5)	(1.8%)

Electric Operating Revenues and Sales Margin – The following table details total Electric Operating Revenues and Sales Margin for the three months ended March 31, 2010 and 2009:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended March 31,			
	2010	2009	$ Change	% Change(1)
Electric Operating Revenue:				
Residential	**$ 28.1**	$ 33.2	$ (5.1)	(8.2%)
Commercial / Industrial	**22.7**	28.9	(6.2)	(10.0%)
Total Electric Operating Revenue	**$ 50.8**	$ 62.1	$ (11.3)	(18.2%)
Cost of Electric Sales:				
Purchased Electricity	**$ 35.8**	$ 47.2	$ (11.4)	(18.3%)
Conservation & Load Management	**0.9**	0.5	0.4	0.6%
Electric Sales Margin	**$ 14.1**	$ 14.4	$ (0.3)	(0.5%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues decreased by $11.3 million, or 18.2%, in the three months ended March 31, 2010 compared to the same period in 2009. Total Electric Operating Revenues include the recovery of approved costs of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The decrease in Total Electric Operating Revenues in the three months ended March 31, 2010 reflects lower Purchased Electricity costs of $11.4 million and lower sales margin of $0.3 million, partially offset by higher C&LM revenues of $0.4 million.

The Purchased Electricity and C&LM component of Total Electric Operating Revenues decreased a combined $11.0 million, or 17.7%, in the three months ended March 31, 2010 compared to the same period in 2009, reflecting lower electric commodity prices and lower electric kWh sales. Purchased Electricity revenues include the recovery of the approved cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the approved cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin decreased $0.3 million in the three months ended March 31, 2010 compared to the same period in 2009, reflecting lower sales volumes. The lower sales are primarily driven by lower average usage per customer reflecting the milder winter weather as well as energy conservation efforts by our customers.

Operating Revenue - Other

The following table details total Other Operating Revenue for the three months ended March 31, 2010 and 2009:

Other Operating Revenue (Millions)

	Three Months Ended March 31,			
	2010	2009	$ Change	% Change
Other	**$ 1.1**	$ 1.1	$ —	—
Total Other Operating Revenue	**$ 1.1**	$ 1.1	$ —	—

Total Other Operating Revenue was unchanged in the three month period ended March 31, 2010 compared to the same period in 2009. Other operating revenues consist of revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Gas – Purchased Gas includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $10.1 million, or 20.9%, in the three month period ended March 31, 2010 compared to the same period in 2009. The decrease in Purchased Gas reflects lower natural gas commodity prices and the lower sales of natural gas, discussed above. The Company recovers the approved costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in approved expenses do not affect earnings.

Purchased Electricity – Purchased Electricity includes the cost of electric supply as well as other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity decreased $11.4 million, or 24.2%, in the three month period ended March 31, 2010 compared to the same period in 2009, reflecting lower electric commodity prices and lower electric kWh sales, discussed above. The Company recovers the approved costs of Purchased Electricity in its rates at cost and therefore changes in approved expenses do not affect earnings.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating costs of the Company's non-regulated business activities. O&M expenses increased $1.8 million in the three months ended March 31, 2010 compared to the same period in 2009. The increase in O&M expenses primarily reflects higher utility operating costs associated with the completion of the transition and full integration of Northern Utilities and Granite State operations into the Company's consolidated operating results in the current period.

Conservation & Load Management – Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 60% of these costs are related to electric operations and 40% to gas operations.

Total Conservation & Load Management expenses increased by $0.6 million in the three months ended March 31, 2010 compared to the same period in 2009. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect earnings.

Table of Contents

Depreciation, Amortization and Taxes

Depreciation and Amortization – Depreciation and Amortization expense increased $0.8 million, or 12.7%, in the three months ended March 31, 2010 compared to the same period in 2009. The increase reflects higher depreciation on normal utility plant additions partially offset by lower amortization expenses.

Local Property and Other Taxes – Local Property and Other Taxes increased by $0.1 million, or 3.3%, in the three months ended March 31, 2010 compared to the same period in 2009. The increase reflects higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes – Federal and State Income Taxes were lower by $1.4 million for the three months ended March 31, 2010 compared to the same period in 2009 reflecting lower pre-tax earnings in the current quarter.

Other Non-Operating Expense

Other Non-operating Expenses increased by $0.1 million in the three month period ended March 31, 2010 compared to the same period in 2009.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Consistent with regulatory precedent, interest income is recorded on an under-collection of costs, including carrying charges of $0.3 million in 2010 on deferred storm costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset. The three months ended March 31, 2009 include approximately $0.6 million of interest expense on the Company's interim bank financing facility used to finance the acquisitions of Northern Utilities and Granite State, which was repaid in the second quarter of 2009 upon the Company's issuance of additional equity.

Interest Expense, Net (millions)	**Three Months Ended March 31,**		
	2010	**2009**	**Change**
Interest Expense			
Long-term Debt	**$ 4.7**	$ 4.6	$ 0.1
Short-term Debt	**0.4**	1.1	(0.7)
Regulatory Liabilities	**0.1**	—	0.1
Subtotal Interest Expense	**5.2**	5.7	(0.5)
Interest (Income)			
Regulatory Assets	**(0.8)**	(0.7)	(0.1)
AFUDC and Other	**(0.1)**	(0.2)	0.1
Subtotal Interest (Income)	**(0.9)**	(0.9)	—
Total Interest Expense, Net	**$ 4.3**	$ 4.8	$ (0.5)

Interest Expense, Net decreased $0.5 million in the three months ended March 31, 2010 compared to the same period in 2009 reflecting higher acquisition related debt fees incurred in 2009 and lower average borrowings in the current quarter.

On March 2, 2010, UES completed the sale of $15 million of First Mortgage Bonds through a private placement to institutional investors. The First Mortgage Bonds have a maturity of ten years and a coupon rate of 5.24%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On March 2, 2010, Northern Utilities completed the sale of $25 million of Senior Unsecured Notes through a private placement to institutional investors. The Senior Unsecured Notes have a maturity of ten years and a coupon rate of 5.29%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally generated funds through bank borrowings, as needed, under its unsecured short-term bank credit facility. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

At March 31, 2010, the Company had $19.3 million in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of March 31, 2010, the Company was in compliance with the financial covenants contained in the revolving credit facility.

The Company provides limited guarantees on certain energy and natural gas storage management contracts entered into by the distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2010, there were approximately $39.2 million of guarantees outstanding and the longest term guarantee extends through December 31, 2010.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of March 31, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $4.1 million, and the principal amount outstanding for the 7.15% Granite State notes was $10.0 million.

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Cash Flows

Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for the three months ended March 31, 2010 compared to the same period in 2009.

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Cash Provided by Operating Activities	**$ 24.3**	$ 31.8

Cash Provided by Operating Activities – Cash Provided by Operating Activities was $24.3 million in the first three months of 2010, a decrease of $7.5 million over the comparable period in 2009. In the first three months of 2010 as compared to the first three months of 2009, Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes decreased by $5.2 million, cash provided by working capital decreased $3.1 million, and cash provided by all other Operating Activities increased $0.8 million.

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Cash (Used in) Investing Activities	**$ (10.3)**	$ (18.0)

Cash (Used in) Investing Activities – Cash (Used in) Investing Activities was $10.3 million for the three months ended March 31, 2010 compared to $18.0 million for the same period in 2009. Capital spending in the first three months of 2010 includes $4.1 million as a result of a wind storm in February 2010, and capital spending in the same period of 2009 includes $9.9 million resulting from the December 2008 ice storm. All other capital spending in the first three months of 2010 was $6.2 million compared to $8.1 million in the same period of 2009. Capital expenditures are projected to be approximately $64 million in 2010 and $60 million in 2011, reflecting normal electric and gas utility system additions.

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Cash (Used in) Financing Activities	**$ (12.9)**	$ (10.8)

Cash (Used in) Financing Activities – Cash (Used in) Financing Activities was $12.9 million in the three months ended March 31, 2010. In March 2010, Unitil Energy and Northern Utilities closed long-term debt financings of $15.0 million and $25.0 million, respectively. The net proceeds of these financings were used to refinance short-term borrowings. Short-term borrowings were reduced by $45.2 million in the first three months of 2010 which reflects the net borrowing (repayment) of bank borrowings under our revolving credit agreement. Other uses of cash include $3.8 million for quarterly dividend payments and $3.8 million related to gas supply inventory financing. Proceeds from issuances of common stock provided a source of cash of $0.2 million, and all other uses of cash were $0.3 million.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 10, 2010.

Regulatory Accounting – The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite State, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)

	March 31,		December 31,
	2010	**2009**	**2009**
Energy Supply Contract Obligations	**$ 31.2**	$ 47.7	$ 34.7
Deferred Restructuring Costs	**27.7**	30.6	28.3
Generation-related Assets	**—**	0.6	—
Subtotal – Restructuring Related Items	**58.9**	78.9	63.0
Retirement Benefit Obligations	**43.8**	45.3	43.7
Income Taxes	**14.0**	15.6	14.5
Environmental Obligations	**21.9**	22.0	22.7
Deferred Storm Charges	**19.6**	0.6	14.6
Other	**8.2**	12.0	7.9
Total Regulatory Assets	**$ 166.4**	$ 174.4	$ 166.4
Less: Current Portion of Regulatory Assets[(1)]	**19.0**	30.2	21.9
Regulatory Assets - noncurrent	**$ 147.4**	$ 144.2	$ 144.5

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Utility Revenue Recognition – Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts – The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations – The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2009 and 2008, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000 and $200,000, respectively, in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2009 and 2008, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $735,000 and $675,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $576,000 and $531,000, respectively. See Note 8 to the accompanying Consolidated Financial Statements.

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes.

Table of Contents

These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets.

Depreciation – Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies – The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of March 31, 2010, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

As of March 31, 2010, the Company and its subsidiaries had 433 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of March 31, 2010, 149 of the Company's employees were represented by labor unions. These employees are covered by collective bargaining agreements. Two agreements expire on May 31, 2010, one agreement expires on June 5, 2010 and one agreement expires on March 31, 2012. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rates on the Company's short-term borrowings for the three months ended March 31, 2010 and March 31, 2009 were 2.26% and 4.78%, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Table of Contents

Item 1. *Financial Statements*

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions, except common shares and per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2010	**2009**
Operating Revenues		
Gas	**$ 61.1**	$ 72.4
Electric	**50.8**	62.1
Other	**1.1**	1.1
Total Operating Revenues	**113.0**	135.6
Operating Expenses		
Purchased Gas	**38.3**	48.4
Purchased Electricity	**35.8**	47.2
Operation and Maintenance	**12.2**	10.4
Conservation & Load Management	**1.7**	1.1
Depreciation and Amortization	**7.1**	6.3
Provisions for Taxes:		
Local Property and Other	**3.1**	3.0
Federal and State Income	**3.9**	5.3
Total Operating Expenses	**102.1**	121.7
Operating Income	**10.9**	13.9
Other Non-Operating Expense (Income)	**0.1**	—
Income Before Interest Expense	**10.8**	13.9
Interest Expense, Net	**4.3**	4.8
Net Income	**6.5**	9.1
Less: Dividends on Preferred Stock	**—**	—
Earnings Applicable to Common Shareholders	**$ 6.5**	$ 9.1
Weighted Average Common Shares Outstanding – Basic (000's)	**10,801**	8,018
Weighted Average Common Shares Outstanding – Diluted (000's)	**10,803**	8,018
Earnings Per Common Share (Basic and Diluted)	**$ 0.61**	$ 1.14
Dividends Declared Per Share of Common Stock	**$ 0.69**	$ 0.69

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) March 31, 2010	(UNAUDITED) March 31, 2009	December 31, 2009
ASSETS:			
Utility Plant:			
Electric	**$ 310.8**	$ 297.2	$ 302.3
Gas	**327.9**	309.1	325.5
Common	**29.5**	30.4	28.9
Construction Work in Progress	**24.8**	10.4	26.0
Total Utility Plant	**693.0**	647.1	682.7
Less: Accumulated Depreciation	**237.9**	218.6	233.0
Net Utility Plant	**455.1**	428.5	449.7
Current Assets:			
Cash	**8.8**	14.5	7.7
Accounts Receivable – Net of Allowance for Doubtful Accounts of $3.0, $3.7 and $2.5	**40.3**	51.9	33.5
Accrued Revenue	**27.4**	46.1	44.0
Gas Inventory	**6.6**	8.7	14.3
Materials and Supplies	**2.9**	3.1	2.6
Prepayments and Other	**3.8**	2.9	4.7
Total Current Assets	**89.8**	127.2	106.8
Noncurrent Assets:			
Regulatory Assets	**147.4**	144.2	144.5
Other Noncurrent Assets	**25.6**	22.4	24.2
Total Noncurrent Assets	**173.0**	166.6	168.7
TOTAL	**$ 717.9**	$ 722.3	$ 725.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) March 31, 2010	(UNAUDITED) March 31, 2009	December 31, 2009
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 192.6**	$ 148.5	$ 193.1
Preferred Stock	**2.0**	2.0	2.0
Long-Term Debt, Less Current Portion	**288.7**	249.2	248.9
Total Capitalization	**483.3**	399.7	444.0
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.4	0.4
Accounts Payable	**17.8**	29.9	25.1
Short-Term Debt	**19.3**	87.7	64.5
Energy Supply Contract Obligations	**18.1**	21.6	23.1
Other Current Liabilities	**32.1**	32.5	16.6
Total Current Liabilities	**87.7**	172.1	129.7
Deferred Income Taxes	**34.3**	29.1	39.8
Noncurrent Liabilities:			
Energy Supply Contract Obligations	**19.4**	31.2	21.7
Retirement Benefit Obligations	**68.2**	69.7	65.5
Environmental Obligations	**14.3**	11.4	14.3
Other Noncurrent Liabilities	**10.7**	9.1	10.2
Total Noncurrent Liabilities	**112.6**	121.4	111.7
TOTAL	**$ 717.9**	$ 722.3	$ 725.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

[Table of Contents](#)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Three Months Ended March 31,	
	2010	**2009**
Operating Activities:		
Net Income	**$ 6.5**	$ 9.1
Adjustments to Reconcile Net Income to Cash		
Provided by Operating Activities:		
Depreciation and Amortization	**7.1**	6.3
Deferred Tax Provision	**(5.2)**	(1.8)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**(6.8)**	(12.2)
Accrued Revenue	**16.6**	9.4
Gas Inventory	**7.7**	22.9
Accounts Payable	**(7.3)**	1.4
All other Current Assets and Liabilities	**6.8**	(1.4)
Other, net	**(1.1)**	(1.9)
Cash Provided by Operating Activities	**24.3**	31.8
Investing Activities:		
Property, Plant and Equipment Additions	**(10.3)**	(18.0)
Cash (Used in) Investing Activities	**(10.3)**	(18.0)
Financing Activities:		
Proceeds from (Repayment of) Short-Term Debt	**(45.2)**	13.6
Proceeds from Issuance of Long-Term Debt	**40.0**	—
Net Decrease in Gas Inventory Financing	**(3.8)**	(26.8)
Dividends Paid	**(3.8)**	(2.8)
Proceeds from Issuance of Common Stock, net	**0.2**	5.4
Other, net	**(0.3)**	(0.2)
Cash (Used in) Financing Activities	**(12.9)**	(10.8)
Net Increase in Cash	**1.1**	3.0
Cash at Beginning of Period	**7.7**	11.5
Cash at End of Period	**$ 8.8**	$ 14.5
Supplemental Cash Flow Information:		
Interest Paid	**$ 2.0**	$ 2.6
Income Taxes Paid	**1.0**	—

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite State), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite State, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the "Acquisitions"). The final purchase price allocation is disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on February 10, 2010.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern and central Maine and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the distribution utilities).

Granite State is a natural gas transportation pipeline, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite State provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite State derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third –party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service; Unitil Realty; and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three months ended March 31, 2010 are not necessarily indicative of results to be expected for the year ending December 31, 2010. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of

Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission (SEC) on February 10, 2010, for a description of the Company's Basis of Presentation.

As a result of the issuance of new common shares, discussed below, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Accounting Codification–In June 2009, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 168). SFAS No. 168 was effective for financial statements for interim and annual periods ending after September 15, 2009. The Company has adopted SFAS No. 168 and therefore all references by the Company to authoritative accounting principles recognized by the FASB reflect the FASB Codification.

Derivatives – The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases natural gas futures contracts on the New York Mercantile Exchange (NYMEX) that correspond to the associated delivery month. Any gains or losses on the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company records gains and losses as regulatory liabilities or assets, recognizes such gains or losses in Purchased Gas and these gains and losses are passed through to customers through rate reconciling mechanisms.

As of March 31, 2010 and December 31, 2009, the Company had 1.2 billion and 1.9 billion cubic feet (BCF), respectively, outstanding in natural gas purchase contracts under its hedging program. The following table provides information on the hedging instruments.

Natural Gas Futures Contracts ($millions)

	As of March 31, 2010		As of December 31, 2009	
Balance Sheet Location	Current and Noncurrent	Liabilities	Current and Noncurrent	Liabilities
Fair Value	$	1.9	$	2.3
Amount of Gain (Loss) Recognized in Regulatory Asset / Liability for Derivatives (1)	$	(3.1)	$	(2.9)

For the Three Months Ended March 31, 2010

Location of Gain (Loss) Reclassified from Regulatory Asset / Liability into Consolidated Statement of Earnings	Purchased Gas	
Amount of Gain (Loss) Reclassified from Regulatory Asset / Liability into Consolidated Statement of Earnings	$	(2.3)

(1) Includes approximately $1.2 million of loss on contracts designated for April 2010 that were physically sold in March 2010 and the impact on the Consolidated Balance Sheet has been deferred until April 2010 when the natural gas is used.

Subsequent Events – On April 15, 2010 Unitil Energy filed a proposed base rate increase of $10.1 million which represents an increase of 6.5 percent above present rates. Unitil Energy requested temporary rates to be effective July 1, 2010. In addition, Unitil Energy requested adjustments for a Rate Year Step Adjustment, a Large Capital Project Step Adjustment and a long-term rate plan establishing step adjustments associated with the Company's Reliability Enhancement Plan and Vegetation Management Plan. A decision from the NHPUC on Unitil Energy's rate increase request may take up to one year.

The Company has evaluated all events or transactions through the date of this filing. During this period, the Company did not have any material subsequent events that impacted its consolidated financial statements.

Reclassifications – Based on the Company's analysis certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation.

Recently Issued Pronouncements – There are no recently issued pronouncements that the Company has not already adopted.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
03/25/10	05/14/10	04/30/10	$ 0.345
01/14/10	02/16/10	02/02/10	$ 0.345
09/23/09	11/16/09	11/2/09	$ 0.345
06/18/09	08/14/09	07/31/09	$ 0.345
03/26/09	05/15/09	05/01/09	$ 0.345
01/15/09	02/16/09	02/02/09	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

Common Stock

The Company's common stock trades under the symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 10,859,442, 8,105,540 and 10,836,759 of common shares outstanding at March 31, 2010, March 31, 2009 and December 31, 2009, respectively.

Unitil Corporation Common Stock Offering – Between December 2008 and June 2009, the Company sold 4,970,000 shares of its common stock at a price of $20.00 per share in registered public offerings. The Company used the net proceeds of $93.1 million from these offerings primarily to complete the acquisition of Northern Utilities and Granite State. Please see Note 3 to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2009 as filed with the SEC on February 10, 2010 for additional information.

Dividend Reinvestment and Stock Purchase Plan – During the first quarter of 2010, the Company sold 10,328 shares of its Common Stock, at an average price of $21.78 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $225,000 were used to reduce short-term borrowings.

During the first quarter of 2009, the Company sold 11,663 shares of its Common Stock, at an average price of $20.29 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $237,000 were used to reduce short-term borrowings.

Restricted Stock Plan – The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 5, 2010, 12,520 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $262,920. There were 42,000 and 49,053 non-vested shares under the Plan as of March 31, 2010 and 2009, respectively. The weighted average grant date fair value of these shares was $22.13 and $23.06, respectively. The compensation expense associated with the issuance of shares under the Plan is being recognized over the vesting period and was $0.1 million and $0.1 million for the three months ended March 31, 2010 and 2009, respectively. At March 31, 2010, there was approximately $1.1 million of total unrecognized compensation cost under the Plan which is expected to be recognized over approximately 2.9 years. There were 165 restricted shares forfeited under the Plan during the three months ended March 31, 2010. There were no cancellations under the Plan during the three months ended March 31, 2010.

Preferred Stock

Details on preferred stock at March 31, 2010, March 31, 2009 and December 31, 2009 are shown below:

(Amounts in Millions)

	March 31,		December 31,
	2010	2009	2009
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	$ 0.2	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	0.8	0.8	0.8
8.00% Series, $100 Par Value	1.0	1.0	1.0
Total Preferred Stock	$ 2.0	$ 2.0	$ 2.0

Table of Contents

NOTE 4 – LONG-TERM DEBT, CREDIT ARRANGEMENTS AND GUARANTEES

Long-Term Debt

Details on long-term debt at March 31, 2010, March 31, 2009 and December 31, 2009 are shown below ($ Millions):

	March 31,		December 31,
	2010	2009	2009
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
5.24% Series, Due March 2, 2020	**15.0**	—	—
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Northern Utilities Senior Notes:			
6.95% Senior Notes, Series A, Due December 3, 2018	**30.0**	30.0	30.0
5.29% Senior Notes, Due March 2, 2020	**25.0**	—	—
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	50.0	50.0
Granite State Senior Notes:			
7.15% Senior Notes, Due December 15, 2018	**10.0**	10.0	10.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due Through August 1, 2017	**4.1**	4.6	4.3
Total Long-Term Debt	**289.1**	249.6	249.3
Less: Current Portion	**0.4**	0.4	0.4
Total Long-term Debt, Less Current Portion	**$ 288.7**	$ 249.2	$ 248.9

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at March 31, 2010 is estimated to be approximately $310 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

On March 2, 2010, UES completed the sale of $15 million of First Mortgage Bonds through a private placement to institutional investors. The First Mortgage Bonds have a maturity of ten years and a coupon rate of 5.24%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On March 2, 2010, Northern Utilities completed the sale of $25 million of Senior Unsecured Notes through a private placement to institutional investors. The Senior Unsecured Notes have a maturity of ten years and a coupon rate of 5.29%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

Credit Arrangements

At March 31, 2010, the Company had $19.3 million in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter. As of March 31, 2010, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 13, 2009, the Company entered into an amendment to its 364-day revolving credit facility with Bank of America, as administrative agent, and a syndicate of lenders. The Company originally entered into the facility on November 26, 2008. The amendment increases the maximum borrowings under the facility from $60 million to $80 million.

Northern enters into asset management agreements under which Northern releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $6.2 million and $5.0 million outstanding at March 31, 2010 and March 31, 2009, respectively, related to these asset management agreements.

Guarantees

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2010 there are $39.2 million of guarantees outstanding and the longest of these guarantees extends through December 31, 2010. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage Agreement discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite State. As of March 31, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $4.1 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite State notes due 2018. As of March 31, 2010, the principal amount outstanding for the 7.15% Granite State notes was $10.0 million. This guarantee will terminate if Granite State reorganizes and merges with and into Northern Utilities.

Table of Contents

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three months ended March 31, 2010 and March 31, 2009:

Three Months Ended March 31, 2010 (Millions)	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$ 50.8**	**$ 61.1**	**$ —**	**$ 1.1**	**$ 113.0**
Segment Profit	**1.3**	**4.6**	**0.2**	**0.4**	**6.5**
Identifiable Segment Assets	**357.3**	**348.5**	**7.9**	**4.2**	**717.9**
Capital Expenditures	**6.9**	**2.8**	**0.6**	**—**	**10.3**
Three Months Ended March 31, 2009 (Millions)					
Revenues	$ 62.1	$ 72.4	$ —	$ 1.1	$ 135.6
Segment Profit (Loss)	1.5	7.6	(0.4)	0.4	9.1
Identifiable Segment Assets	355.5	354.8	10.2	1.8	722.3
Capital Expenditures	13.3	4.6	0.1	—	18.0

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2009 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 10, 2010.

Legal Proceedings

A putative class action Complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009 an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2010. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Regulatory Matters

Unitil Energy Rate Case Filing – On April 15, 2010 Unitil Energy filed a proposed base rate increase of $10.1 million which represents an increase of 6.5 percent above present rates. Unitil Energy requested temporary rates to be effective July 1, 2010. In addition, Unitil Energy requested adjustments for a Rate Year Step Adjustment, a Large Capital Project Step Adjustment and a long-term rate plan establishing step adjustments associated with the Company's Reliability Enhancement Plan and Vegetation Management Plan. A decision from the NHPUC on Unitil Energy's rate increase request may take up to one year.

Major Ice Storm – On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region. The Company spent approximately $23 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.3 million related to capital construction and $15.0 million, including carrying charges, which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

The MDPU conducted an investigation of Fitchburg's preparation for and response to the December 2008 Ice Storm during the first half of 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service. As a result, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices, and also directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. On April 20, 2010 the Company issued Requests for Proposals to perform the independent management audit in accordance with the schedule set by the MDPU. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

On July 28, 2009, Fitchburg filed with the MDPU a petition for approval to defer and record as a regulatory asset approximately $11.5 million of costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. On December 30, 2009, the MDPU approved the request. The order of approval made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. As of March 31, 2010, March 31, 2009 and December 31, 2009, Fitchburg has deferred approximately $12.6 million, $0.4 million and $12.3 million of costs, respectively, including carrying charges, associated with the repair of its electric distribution system for future recovery in rates.

On August 26, 2009, Unitil Energy filed a petition with the NHPUC requesting an accounting order authorizing Unitil Energy to record as a regulatory asset approximately $2 million in expenses associated with network damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's next base rate case. On November 9, 2009, the NHPUC granted the requested accounting order, clarifying that such issues as the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are issues that will be deferred to Unitil Energy's next rate case. As of March 31, 2010, March 31, 2009 and December 31, 2009, Unitil Energy has deferred approximately $2.4 million, $0.2 million and $2.3 million of costs, respectively, including carrying charges, associated with the repair of its electric distribution system for future recovery in rates.

On December 3, 2009, the NHPUC issued its final report regarding its review of the December 2008 Ice Storm. The report stated that the NHPUC will commence an adjudicative proceeding to examine the reasonableness of Unitil's response to the December 2008 Ice Storm. On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. This matter remains pending.

Fitchburg – Electric Division – On November 25, 2009, Fitchburg submitted its annual reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). In addition, the Standard Offer Service and Default Service Costs incurred during the seven year Standard Offer Service period that ended February 28, 2005 have been combined and recovery is proposed through a Transition Charge Surcharge of $0.00400 per kWh. Changes to the Pension/PBOP Adjustment and Residential Assistance Adjustment Factor were proposed in other proceedings. The rates were approved effective January 1, 2010, subject to reconciliation pending investigation by the MDPU. This matter remains pending. A final order approving Fitchburg's 2008 Annual Reconciliation Filing was issued on April 12, 2010.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting the items required by House Bill 4329.

Fitchburg – Gas Operations – On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg believes that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

During the summer of 2009, Fitchburg operated its gas system entirely on local production from LNG for approximately three months due to construction on the lateral from Tennessee Gas Pipeline, which is the sole source of pipeline gas to Fitchburg. During this time Fitchburg provided gas LNG supply to all firm sales customers and also to the retail marketers for delivery to firm customers who have contracted for third party supply. Fitchburg's management of this project was reviewed by the MDPU during its last Integrated Resource Plan proceeding, before the shutdown occurred. In its order, the MDPU stated it would investigate the costs associated with the shutdown in Fitchburg's March 2010 Cost of Gas Adjustment Clause filing when its actual costs will be reconciled with its projected costs.

Fitchburg – Other – On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, including company-specific rate cases. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012.

On February 11, 2009, the MA Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, and special tariffs to allow the net metering of customer-owned renewable generation. Three year energy efficiency investment plans, plans to establish smart grid pilot programs, and net metering tariffs have been approved by the MDPU. Proposals to purchase long-term contracts for renewable energy are under review in a separately designated docket.

Unitil Energy – Other – In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources. This matter remains pending before the NHPUC.

On February 25, 2010, a significant wind storm struck portions of the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including approximately 85% of the Company's customers. Unitil Energy was able to restore power to 96% percent of its customers by day three, and its final customers, including those with individual service problems, were restored by day four. As a result of this storm, the Company estimates that it has spent approximately $9.0 million for the repair and replacement of electric distribution systems damaged during the storm. Unitil Energy, in its base rate case filing discussed above, has requested recovery in rates for the costs associated with the emergency repair of its electric distribution system for damage caused by this storm. The amount and timing of the cost recovery of these storm restoration expenditures will be determined in the base rate case proceeding. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

Northern Utilities – On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation ("NOPVs") of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern's distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at March 31, 2010 was $2.3 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in the Portland and Westbrook service areas. Northern Utilities has filed a proposed accelerated replacement program for the MPUC's consideration. A final decision on this matter is expected by year-end.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2009 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 10, 2010.

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of March 31, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at March 31, 2010, March 31, 2009 and December 31, 2009 are non-current accrued liabilities totaling $12.0 million, $10.8 million and $12.0 million, respectively, related to estimated future clean up costs for permanent remediation of a former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties. Also included on the Company's Consolidated Balance Sheet at March 31, 2010, March 31, 2009 and December 31, 2009 are current and non-current accrued liabilities totaling $2.5 million, $2.4 million and $2.5 million, respectively, associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the recovery of these environmental remediation costs is probable through the regulatory process.

Table of Contents

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company co-sponsors the Unitil Corporation Retirement Plan (Pension Plan), the Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan), and the Unitil Corporation Supplemental Executive Retirement Plan (SERP) to provide certain pension and postretirement benefits for its retirees and current employees. Please see Note 9 to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2009 as filed with the SEC on February 10, 2010 for additional information regarding these plans.

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

	2010	2009
Used to Determine Plan Costs		
Discount Rate	**5.75%**	6.25%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan		PBOP Plan		SERP	
Three Months Ended March 31,	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Service Cost	**$ 652**	$ 571	**$ 367**	$ 357	**$ 71**	$ 54
Interest Cost	**1,114**	1,073	**504**	578	**57**	45
Expected Return on Plan Assets	**(1,045)**	(1,108)	**(150)**	(89)	**—**	—
Prior Service Cost Amortization	**63**	66	**395**	428	**1**	—
Transition Obligation Amortization	**—**	—	**5**	5	**—**	—
Actuarial Loss Amortization	**601**	399	**—**	—	**33**	18
Sub-total	**1,385**	1,001	**1,121**	1,279	**162**	117
Amounts Capitalized and Deferred	**(622)**	(282)	**(350)**	(358)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 763**	$ 719	**$ 771**	$ 921	**$ 162**	$ 117

Employer Contributions

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008 - 2010 plan years. This did not affect the Company's Pension Plan in 2009 as its Pension Plan was 94% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2008 and met the exemption from the shortfall amortization. The Company expects to contribute approximately $4.0 million to fund its Pension Plan in 2010.

As of March 31, 2010, the Company had made $13,000 of contributions to the SERP Plan in 2010. The Company presently anticipates contributing $3.5 million to the PBOP Plan and an additional $40,000 to the SERP Plan in 2010.

NOTE 9: INCOME TAXES

The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2009 and for the current interim reporting period ended March 31, 2010 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by the FASB Codification is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2006; December 31, 2007; and December 31, 2008. Income tax filings for the year ended December 31, 2009 have been extended until September 15, 2010. In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized net operating loss (NOL) carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of $5.0 million and $6.7 million, respectively. These NOL carrybacks resulted in a refund to the Company of $4.0 million which was received in November 2009. According to Internal Revenue Code rules, NOL refunds in excess of $2.0 million fall under the jurisdiction of the Joint Committee of Congress (Joint Committee) and are subject to review by the Internal Revenue Service (IRS) and attorneys of the Joint Committee. As a result, on December 30, 2009, the Company received notice that its Federal Income Tax return filings for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 are under examination by the IRS. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in the Company's internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

[Table of Contents](#)

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2009 as filed with the SEC on February 10, 2010.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended March 31, 2010.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 26, 2009, the Company periodically repurchased shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. There was no pool or maximum number of shares related to these purchases; however, the trading plan automatically terminated when $83,000 in value of shares were purchased so that, as of March 31, 2010, the value of shares that may yet be purchased under that trading plan was $0.

The Company adopted a new written trading plan under Rule 10b5-1 under the Exchange Act on March 25, 2010, covering the period March 25, 2010 through March 25, 2011. The Company may suspend or terminate this trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases; however, the trading plan will terminate when $80,700 in value of shares have been purchased or, if sooner, on March 25, 2011.

The Company's repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
1/1/10 – 1/31/10	—	—	—
2/1/10 – 2/28/10	—	—	—
3/1/10 – 3/31/10	139	$ 22.24	139
Total	139	$ 22.24	139

Item 5. Other Information

On April 27, 2010, the Company issued a press release announcing its results of operations for the three-month period ended March 31, 2010. The press release is furnished with the Quarterly Report on Form 10-Q as Exhibit 99.1.

Table of Contents

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated April 27, 2010 Announcing Earnings For the Quarter Ended March 31, 2010.	Filed herewith

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	UNITIL CORPORATION
	(Registrant)
Date: April 27, 2010	/s/ Mark H. Collin
	Mark H. Collin Chief Financial Officer
Date: April 27, 2010	/s/ Laurence M. Brock
	Laurence M. Brock Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated April 27, 2010 Announcing Earnings For the Quarter Ended March 31, 2010.	Filed herewith

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING
(Millions, except for per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2010	**2009**
Net Income	**$ 6.5**	$ 9.1
Less: Dividend Requirements on Preferred Stock	**—**	—
Net Income Applicable to Common Stock	**$ 6.5**	$ 9.1
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**10,801**	8,018
Dilutive Effect of Stock Options and Restricted Stock (000's)	**2**	—
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**10,803**	8,018
Earnings Per Share – Basic	**$ 0.61**	$ 1.14
Earnings Per Share – Diluted	**$ 0.61**	$ 1.14

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 27, 2010
/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 27, 2010
/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 27, 2010

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending March 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	April 27, 2010
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	April 27, 2010
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	April 27, 2010

For Immediate Release

Exhibit 99.1

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports First Quarter Earnings

Hampton, NH – April 27, 2010: Unitil Corporation (NYSE: UTL) (www.unitil.com) today announced Earnings Applicable to Common Shareholders of $6.5 million for the first quarter of 2010 compared to 2009 first quarter earnings of $9.1 million. Earnings per common share (EPS) were $0.61 for the three months ended March 31, 2010 compared to EPS of $1.14 in the first quarter of 2009. Earnings per share in the first quarter of 2010 are not directly comparable with 2009 due to a 35% increase in average common shares outstanding year over year resulting from the issuance of new common equity in 2009 to complete the financing of the Company's acquisition of Northern Utilities and Granite State.

"Lower sales due to warmer than normal winter temperatures and the continued slow economic recovery in the region resulted in significantly lower earnings in the first quarter of 2010 compared to last year," said Robert G. Schoenberger, Unitil's Chairman and Chief Executive Officer. "Over the next 12 to 18 months we will be filing for rate relief for all our utility subsidiaries to align our revenues and operating costs and to recover the significant investments we are making to provide safe, reliable and cost effective electric and gas service to our customers. On April 15, 2010 we filed the first of these rate cases seeking a $10.1 million rate adjustment for our electric operations in New Hampshire."

Natural gas sales margin decreased $1.4 million in the three months ended March 31, 2010 compared to the same period in 2009 reflecting lower sales volumes. Total therm sales of natural gas decreased 6.5% in the three months ended March 31, 2010 compared to the same period in 2009, reflecting decreases of 7.8% and 6.0% in sales to residential and commercial and industrial (C&I) customers, respectively. The lower sales in the first three months of 2010 reflect a milder winter heating season this year. There were 7.6% fewer Heating Degree Days in the Company's service territories in the first quarter of 2010 compared to the same period in 2009. On a weather-normalized basis, natural gas sales decreased by 2.7% in the three months ended March 31, 2010 compared to the same period in 2009.

Electric sales margin decreased $0.3 million in the three months ended March 31, 2010 compared to the same period in 2009, reflecting lower sales volumes. Total electric kilowatt-hour (kWh) sales decreased 1.8% in the three months ended March 31, 2010 compared to the same period in 2009 driven by lower average usage per customer reflecting the milder winter weather as well as energy conservation efforts by our customers. On a weather-normalized basis, kWh sales in the three months ended March 31, 2010 were flat compared to the same period in 2009.

Selected financial data for 2010 is presented in the following table:

Unitil Corporation - Condensed Financial Data

(Millions, except Per Share Data) (Unaudited)

	Three Months Ended March 31, 2010	2009	Change
Gas Therm Sales:			
Residential	17.8	19.3	(7.8%)
Commercial/Industrial	54.6	58.1	(6.0%)
Total Gas Therm Sales	**72.4**	**77.4**	**(6.5%)**
Electric kWh Sales:			
Residential	177.7	180.6	(1.6%)
Commercial/Industrial	237.5	242.1	(1.9%)
Total Electric kWh Sales	**415.2**	**422.7**	**(1.8%)**
Gas Revenues	$ 61.1	$ 72.4	$ (11.3)
Purchased Gas	39.1	49.0	(9.9)
Gas Sales Margin	**22.0**	**23.4**	**(1.4)**
Electric Revenues	50.8	62.1	(11.3)
Purchased Electricity	36.7	47.7	(11.0)
Electric Sales Margin	**14.1**	**14.4**	**(0.3)**
Usource Sales Margin	**1.1**	**1.1**	**—**
Total Sales Margin	**37.2**	**38.9**	**(1.7)**
Operation & Maintenance	12.2	10.4	1.8
Depreciation, Amortization, Taxes & Other	14.2	14.6	(0.4)
Interest Expense, Net	4.3	4.8	(0.5)
Earnings Applicable to Common Shareholders	**$ 6.5**	**$ 9.1**	**$ (2.6)**
Earnings Per Share	**$ 0.61**	**$ 1.14**	**$ (0.53)**

Operation & Maintenance (O&M) expenses increased $1.8 million in the three months ended March 31, 2010 compared to the same period in 2009. The increase in O&M expenses primarily reflects higher utility operating costs associated with the completion of the transition and full integration of Northern Utilities and Granite State operations into the Company's consolidated operating results in the current period.

Depreciation, Amortization, Taxes and Other expenses decreased $0.4 million in the three months ended March 31, 2010 compared to the same period in 2009. Higher depreciation expense on utility plant additions were offset by lower amortization and lower income taxes on lower pre-tax earnings in the quarter.

Interest Expense, Net decreased $0.5 million in the three months ended March 31, 2010 compared to the same period in 2009 reflecting higher acquisition related debt fees incurred in 2009 and lower average borrowings in the current quarter.

Also in the first quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

Additionally, EPS in the first quarter of 2010 reflect a higher number of average shares outstanding year over year. In May and June 2009, the Company sold 2,700,000 shares of its common stock at a price of $20.00 per share in a registered public offering. The Company used the net proceeds of $51.2 million from this offering to complete the acquisition of Northern Utilities and Granite State.

As a result of the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

The Company will hold a quarterly conference call to discuss first quarter 2010 results on Tuesday, April 27, 2010, at 2:00 p.m. Eastern Time. This call is being webcast by Thomson Financial and can be accessed in the Investor Relations section of Unitil Corporation's website, www.unitil.com. Institutional investors can access the call via Thomson StreetEvents (www.streetevents.com), a password-protected event management site.

About Unitil

Unitil Corporation is a public utility holding company headquartered in Hampton, New Hampshire. Unitil's principal business is the local distribution of electricity and natural gas in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three distribution utilities: (i) Unitil Energy Systems, Inc., which provides electric service in the southeastern seacoast and state capital regions of New Hampshire; (ii) Fitchburg Gas and Electric Light Company, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and (iii) Northern Utilities, Inc., which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine. In addition, Unitil is the parent company of Granite State Gas Transmission, Inc., an interstate natural gas transmission pipeline in New Hampshire and Maine. Together, Unitil's operating utilities serve approximately 100,500 electric customers and 70,000, natural gas customers. Unitil's non-regulated business, Usource, also provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

**QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934**
For Quarter Ended June 30, 2010

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire **(State or other jurisdiction of incorporation or organization)**	**02-0381573** **(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire **(Address of principal executive office)**	**03842-1720** **(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 26, 2010
Common Stock, No par value	**10,870,981 Shares**

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended June 30, 2010

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, Inc. (Northern Utilities), a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State Gas Company and (ii) all of the outstanding capital stock of Granite State Gas Transmission, Inc. (Granite), an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (the Acquisition).

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy Systems, Inc. (Unitil Energy), which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg Gas and Electric Light Company (Fitchburg), which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,500 electric customers and 70,000 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite, a natural gas transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite provides Northern Utilities with interconnection to three major natural gas pipelines and access to pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and, combined with Granite, had an investment in Net Utility Plant of $456.6 million at June 30, 2010. Unitil's total operating revenue includes revenue to recover the approved cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not affected by changes in the cost of purchased electricity and natural gas. Earnings from Unitil's utility operations are derived from the return on investment in the three distribution utilities and Granite.

Unitil also conducts non-regulated operations principally through Usource, which is wholly-owned by Unitil Resources Inc., a wholly-owned subsidiary of Unitil. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. The Company's other subsidiaries include Unitil Service Corp., which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, Unitil Realty Corp., which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire and Unitil Power Corp., which formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

RATES AND REGULATION

Base Rate Cases:

On April 15, 2010, Unitil Energy filed a proposed annual base rate increase of $10.1 million with the New Hampshire Public Utilities Commission (NHPUC), which represents an increase of 6.5 percent above present rates. Unitil Energy's filing also included a long-term rate plan establishing base rate step adjustments associated with future planned capital additions and targeted reliability enhancement and vegetation management programs. In its rate filing, Unitil Energy requested that rates initially be set at a lower level on a temporary basis.

On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy. The order provides for a temporary rate increase of $5.2 million (annual) effective July 1, 2010 which will be collected by applying a uniform per kilowatt-hour (kWh) surcharge of $0.00438 to each of Unitil Energy's current rate schedules. Of the $5.2 million rate increase, $500,000 of the increase is intended to permit Unitil Energy to annually recover expenses incurred during the December 2008 ice storm and another $500,000 of the increase is intended to fund higher planned vegetation management program expenditures. Once permanent rates are approved by the NHPUC, they will be reconciled to the date temporary rates were ordered, July 1, 2010. Final review and approval by the NHPUC of Unitil Energy's permanent base rate increase request is currently scheduled to be completed by February 2011.

On June 29, 2010, Granite filed a proposed base transportation rate increase with the FERC, which is Granite's first filing for a rate change since its last general rate case in 1997. If approved as filed, the rate increase would provide for an increase of approximately $3 million in revenue on an annual basis. The rate case filing reflects a rate base of $18.3 million which includes $4.2 million of capital additions to be made through the end of 2010.

In addition to its request for new base transportation rates, Granite, in its rate case filing, is seeking approval to implement a capital cost surcharge that would allow Granite to implement a rate surcharge annually to recover projected capital expenditures of approximately $12.7 million during the three-year time period 2011-2013. Granite expects the FERC regulatory process to result in an effective date of January 1, 2011 for the requested rate increase.

Additionally, Fitchburg and Northern Utilities are currently preparing base rate cases and anticipate filing them with their respective regulatory commissions within the next year.

Other:

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, in regards to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the NHPUC; Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and the Maine Public Utilities Commission (MPUC). Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party suppliers. A majority of Unitil's largest commercial and industrial (C&I) customers purchase their electric and natural gas supplies from third party suppliers. However, most residential and small customers continue to purchase their electric and natural gas supplies through Unitil's distribution utilities. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features. For additional discussion, please refer to Unitil's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 10, 2010.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- The Company's ability to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Recovery of deferred major storm costs;
- Recovery of energy commodity costs;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions that could have an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of our counterparty obligations, including those of our insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended June 30, 2010 and June 30, 2009 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Part I, Item 1 of this report.

Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the Acquisition. As a result of the Acquisition and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisition and stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Earnings Overview

The Company's Earnings (Loss) Applicable to Common Shareholders was a net loss of ($2.1) million for the second quarter of 2010, compared to earnings of $0.2 million for the second quarter of 2009. For the six months ended June 30, 2010, the Company reported net income of $4.4 million compared to $9.3 million for the same period of 2009. Results for the second quarter were driven primarily by higher depreciation and interest expense and lower gas sales margins due to warmer regional temperatures.

Earnings (loss) per common share (EPS) were ($0.19) and $0.41 for the three and six month periods ended June 30, 2010 compared with $0.03 and $1.10 for the same periods of 2009. The Company's results of operations for 2010 are not directly comparable with 2009 due to the issuance of 5.0 million common shares between December 2008 and June 2009 to complete the financing of the Company's acquisition of Northern Utilities and Granite.

Natural gas sales margin decreased $2.4 million and $3.8 million in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009. Total natural gas therm sales were 5.1% and 6.0% lower in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of warmer temperatures in 2010, where there were approximately 22% and 12% fewer Heating Degree Days in the three and six month periods, respectively, compared to the prior year.

Electric sales margin increased $0.4 million and $0.1 million in the three and six months ended June 30, 2010 compared to the same periods in 2009, reflecting higher electric kilowatt-hour (kWh) sales. Total kWh sales increased 5.3% and 1.5% in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009 reflecting increased sales to all customer groups.

O&M expenses decreased $0.4 million and increased $1.4 million for the three and six months ended June 30, 2010, respectively, compared to 2009. The changes in O&M reflect higher utility operating costs and lower professional fees. The increases in utility operating expenses reflect the full integration of Northern Utilities and Granite into the Company's consolidated operating results.

Depreciation and Amortization expense increased $0.7 million and $1.5 million in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009 reflecting normal utility plant additions.

Interest Expense, Net increased $0.8 million and $0.3 million in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in the three and six month periods. Furthermore, net interest expense in 2010 reflects the permanent financing of Northern Utilities and Granite, which was completed in the second quarter of 2009.

Provisions for Federal and State Income Taxes decreased by $2.5 million due to lower pre-tax income in 2010 compared to 2009.

All other items increased $0.3 million and $0.5 million in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009, primarily reflecting higher property and payroll taxes.

Usource, our non-regulated energy brokering business, recorded revenues of $1.1 million and $2.2 million in the three and six month periods ended June 30, 2010, respectively, which were flat compared to the same periods of 2009. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

Additionally, EPS in the three and six months ended June 30, 2010 reflect a higher number of average shares outstanding year over year, as discussed above.

In 2009, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2010, March, 2010 and June 2010 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three and six months ended June 30, 2010 and a period-to-period comparison of changes in financial position are presented below.

Gas Sales, Revenues and Margin

Therm Sales – Total therm sales of natural gas decreased 5.1% and 6.0% in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of warmer temperatures in 2010, where there were approximately 22% and 12% fewer Heating Degree Days in the three and six month periods, respectively, compared to the prior year.

The following table details total firm therm sales for the three and six months ended June 30, 2010 and 2009, by major customer class:

Therm Sales (millions)	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	2009	Change	% Change	2010	2009	Change	% Change
Residential	**6.6**	6.9	(0.3)	(4.3%)	**24.4**	26.2	(1.8)	(6.9%)
Commercial / Industrial	**27.0**	28.5	(1.5)	(5.3%)	**81.6**	86.6	(5.0)	(5.8%)
Total	**33.6**	35.4	(1.8)	(5.1%)	**106.0**	112.8	(6.8)	(6.0%)

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and six months ended June 30, 2010 and 2009:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	**2009**	**$ Change**	**% Change(1)**	**2010**	**2009**	**$ Change**	**% Change(1)**
Gas Operating Revenue:								
Residential	**$10.0**	$ 9.6	$ 0.4	1.7%	**$35.8**	$40.0	$ (4.2)	(4.4%)
Commercial / Industrial	**13.7**	13.8	(0.1)	(0.4%)	**49.0**	55.8	(6.8)	(7.1%)
Total Gas Operating Revenue	**$23.7**	$23.4	$ 0.3	1.3%	**$84.8**	$95.8	$(11.0)	(11.5%)
Cost of Gas Sales:								
Purchased Gas	**$14.3**	$11.8	$ 2.5	10.7%	**$52.6**	$60.2	$ (7.6)	(7.9%)
Conservation & Load Management	**0.8**	0.6	0.2	0.9%	**1.6**	1.2	0.4	0.4%
Gas Sales Margin	**$ 8.6**	$11.0	$ (2.4)	(10.3%)	**$30.6**	$34.4	$ (3.8)	(4.0%)

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $0.3 million, or 1.3%, and decreased $11.0 million, or 11.5%, in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. Total Gas Operating Revenues include the recovery of the approved cost of gas sales, which are recorded as Purchased Gas and Conservation & Load Management (C&LM) in Operating Expenses. The increase in Total Gas Operating Revenues in the second quarter of 2010 reflects higher Purchased Gas revenues of $2.5 million and higher C&LM revenues of $0.2 million, partially offset by lower gas sales margin of $2.4 million. The decrease in Total Gas Operating Revenues in the first six months of 2010 reflects lower Purchased Gas revenues of $7.6 million and lower gas sales margin of $3.8 million, partially offset by higher C&LM revenues of $0.4 million.

The Purchased Gas and C&LM components of Gas Operating Revenues increased a combined $2.7 million, or 11.6%, of Total Gas Operating Revenue and decreased a combined $7.2 million, or 7.5%, of Total Gas Operating Revenue in the three and six month periods ended June 30, 2010 compared to the same periods in 2009. The increase in the second quarter of 2010 is due to higher natural gas commodity costs, increased spending on energy efficiency and conservation programs, partially offset by lower natural gas sales. Also, Purchased Gas in the second quarter of 2010 reflects an adjustment of $0.8 million due to the recognition, for consistency purposes, of commodity-related bad debt expense previously recorded in O&M expense in the first quarter of 2010. The decrease in the six month period of 2010 primarily reflects lower sales of natural gas, partially offset by increased spending on energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin decreased $2.4 million and $3.8 million in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009. The decrease in the three month period principally reflects lower sales of natural gas, which reflect the effect of warmer temperatures, of approximately $0.5 million, lower estimated unbilled revenue in the current period of $1.1 million and the recognition of commodity-related bad debt, discussed above, of $0.8 million. The decrease in the six month period principally reflects lower sales of natural gas, which reflect the effect of the milder winter heating season, of approximately $2.1 million and lower estimated unbilled revenue in the current period of $1.7 million.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Total electric kilowatt-hour (kWh) sales increased 5.3% and 1.5% in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009 reflecting increased sales to all customer groups.

The following table details total kWh sales for the three and six months ended June 30, 2010 and 2009 by major customer class:

kWh Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	**2009**	**Change**	**% Change**	**2010**	**2009**	**Change**	**% Change**
Residential	**148.3**	141.1	7.2	5.1%	**326.0**	321.7	4.3	1.3%
Commercial/Industrial	**245.8**	233.2	12.6	5.4%	**483.3**	475.3	8.0	1.7%
Total	**394.1**	374.3	19.8	5.3%	**809.3**	797.0	12.3	1.5%

Electric Operating Revenues and Sales Margin – The following table details total Electric Operating Revenues and Sales Margin for the three and six month periods ended June 30, 2010 and 2009:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	**2009**	**$ Change**	**% Change(1)**	**2010**	**2009**	**$ Change**	**% Change(1)**
Electric Operating Revenue:								
Residential	**$23.8**	$23.3	$ 0.5	1.1%	**$51.9**	$ 56.4	$ (4.5)	(4.1%)
Commercial/Industrial	**22.8**	23.7	(0.9)	(1.9%)	**45.5**	52.7	(7.2)	(6.6%)
Total Electric Operating Revenue	**$46.6**	$47.0	$ (0.4)	(0.8%)	**$97.4**	$109.1	$ (11.7)	(10.7%)
Cost of Electric Sales:								
Purchased Electricity	**$31.7**	$33.4	$ (1.7)	(3.6%)	**$67.5**	$ 80.6	$ (13.1)	(12.0%)
Conservation & Load Management	**1.7**	0.8	0.9	1.9%	**2.6**	1.3	1.3	1.2%
Electric Sales Margin	**$13.2**	$12.8	$ 0.4	0.9%	**$27.3**	$ 27.2	$ 0.1	0.1%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenue, decreased by $0.4 million, or 0.8%, and $11.7 million, or 10.7%, in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. Total Electric Operating Revenues include the recovery of the approved cost of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The decrease in Total Electric Operating Revenues in the second quarter of 2010 reflects lower Purchased Electricity revenues of $1.7 million, partially offset by higher C&LM revenues of $0.9 million and higher electric sales margin of $0.4 million. The decrease in Total Electric Operating Revenues in the first six months of 2010 reflects lower Purchased Electricity revenues of $13.1 million, partially offset by higher C&LM revenues of $1.3 million and higher electric sales margin of $0.1 million.

The Purchased Electricity and C&LM components of Total Electric Operating Revenues decreased a combined $0.8 million, or 1.7%, and $11.8 million, or 10.8%, of Total Electric Operating Revenues in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. These decreases primarily reflect an increase in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by higher spending on energy efficiency and conservation programs and increased sales. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $0.4 million and $0.1 million in the three and six months ended June 30, 2010 compared to the same periods in 2009, reflecting higher electric kWh sales, as discussed above.

Operating Revenue - Other

The following table details total Other Revenue for the three and six months ended June 30, 2010 and 2009:

Other Revenue (000's)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	**2009**	**$ Change**	**% Change**	**2010**	**2009**	**$ Change**	**% Change**
Other	**$1.1**	$1.1	$ —	—	**$2.2**	$2.2	$ —	—
Total Other Revenue	**$1.1**	$1.1	$ —	—	**$2.2**	$2.2	$ —	—

Total Other Revenue was on par in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. Other Revenues represents revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $2.5 million, or 21.2%, and decreased $7.6 million, or 12.6%, in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009. The increase in the second quarter of 2010 is due to higher natural gas commodity costs partially offset by lower sales of natural gas. Also, Purchased Gas in the second quarter of 2010 reflects an adjustment of $0.8 million due to the recognition, for consistency purposes, of commodity-related bad debt expense previously recorded in O&M expense in the first quarter of 2010. The decrease in the six month period of 2010 primarily reflects lower sales of natural gas. The Company recovers the approved costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity decreased $1.7 million, or 5.1%, and $13.1 million, or 16.3%, in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. These decreases primarily reflect an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity costs, partially offset by increased sales. The Company recovers the approved costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expenses decreased $0.4 million, or 3.3%, and increased $1.4 million, or 6.3%, for the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009. The changes in O&M reflect higher utility operating costs and lower professional fees. Utility operating costs primarily consist of compensation and benefit costs, utility distribution and transmission system maintenance costs, bad debt expenses, office expenses and insurance costs. The increases in utility operating expenses reflect the full integration of Northern Utilities and Granite into the Company's consolidated operating results.

Conservation & Load Management – Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy usage. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 60% of these costs are related to electric operations and 40% to gas operations.

Total C&LM expenses increased $1.1 million, or 78.6% and $1.7 million, or 68.0%, in the three and six month periods ended June 30, 2010 compared to the same periods in 2009. These approved costs are collected from customers on a pass through basis and therefore, fluctuations in program costs do not affect earnings.

Depreciation, Amortization and Taxes

Depreciation and Amortization – Depreciation and Amortization expense increased $0.7 million, or 10.9%, and $1.5 million, or 11.8% in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. These increases reflect higher depreciation on normal utility plant additions.

Local Property and Other Taxes – Local Property and Other Taxes increased $0.3 million and $0.4 million in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. These increases reflect higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes – Federal and State Income Taxes were lower by $1.1 million and $2.5 million in the three and six month periods ended June 30, 2010 compared to the same periods in 2009 reflecting lower pre-tax earnings in the current periods.

Other Non-Operating Expenses (Income)

Other Non-Operating Expenses were on par in the three month period ended June 30, 2010 compared to the same period in 2009 and increased by $0.1 million in the six month period ended June 30, 2010 compared to the same period in 2009.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Consistent with regulatory precedent, interest income is recorded on an under-collection of costs which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (Millions)	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Interest Expense						
Long-term Debt	**$ 5.1**	$ 4.5	$ 0.6	**$ 9.8**	$ 9.1	$ 0.7
Short-term Debt	**0.3**	0.6	(0.3)	**0.8**	1.1	(0.3)
Regulatory Liabilities	**0.1**	0.1	—	**0.2**	0.1	0.1
Subtotal Interest Expense	**5.5**	5.2	0.3	**10.8**	10.3	0.5
Interest (Income)						
Regulatory Assets	**(0.9)**	(0.6)	(0.3)	**(1.7)**	(1.3)	(0.4)
AFUDC[1] and Other	**(0.1)**	(0.9)	0.8	**(0.3)**	(0.5)	0.2
Subtotal Interest (Income)	**(1.0)**	(1.5)	0.5	**(2.0)**	(1.8)	(0.2)
Total Interest Expense, Net	**$ 4.5**	$ 3.7	$ 0.8	**$ 8.8**	$ 8.5	$ 0.3

(1) AFUDC – Allowance for Funds Used During Construction.

Interest Expense, Net increased $0.8 million and $0.3 million in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in the three and six month periods. Furthermore, net interest expense in 2010 reflects the permanent financing of Northern Utilities and Granite, which was completed in the second quarter of 2009.

On March 2, 2010, Unitil Energy completed the sale of $15 million of First Mortgage Bonds through a private placement to institutional investors. The First Mortgage Bonds have a maturity of ten years and a coupon rate of 5.24%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On March 2, 2010, Northern Utilities completed the sale of $25 million of Senior Unsecured Notes through a private placement to institutional investors. The Senior Unsecured Notes have a maturity of ten years and a coupon rate of 5.29%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally-generated funds through bank borrowings, as needed, under its unsecured short-term bank credit facility. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

At June 30, 2010, the Company had $24.6 million in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including certain financial covenants. As of June 30, 2010, the Company was in compliance with the financial covenants contained in the revolving credit facility.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $8.5 million, $3.1 million and $10.0 million outstanding at June 30, 2010, June 30, 2009 and December 31, 2009, respectively, related to these asset management agreements.

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of June 30, 2010 there are $40.8 million of guarantees outstanding and the longest of these guarantees extends through October 31, 2011. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage Agreement discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite. As of June 30, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $4.0 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite notes due 2018. As of June 30, 2010, the principal amount outstanding for the 7.15% Granite notes was $10.0 million.

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Cash Flows

Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for the six months ended June 30, 2010 compared to the same period in 2009.

	Six Months Ended June 30,	
	2010	2009
Cash Provided by Operating Activities	**$ 27.0**	$ 53.5

Cash Provided by Operating Activities – Cash Provided by Operating Activities was $27.0 million in the first six months of 2010 compared to $53.5 million in the same period of 2009. In the first six months of 2010 as compared to the first six months of 2009, net sources of cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes decreased by $6.1 million, changes in current assets and liabilities decreased $19.9 million, and changes in all other Operating Activities decreased $0.5 million. The $19.9 million decrease in changes in current assets and liabilities primarily resulted from a decrease in gas inventory of $19.9 million driven by changes in natural gas prices. The Company finances its gas inventory requirements with asset management agreements (see Credit Arrangements in Note 4).

	Six Months Ended June 30,	
	2010	2009
Cash (Used in) Investing Activities	**$(19.2)**	$(32.2)

Cash (Used in) Investing Activities – Cash (Used in) Investing Activities was ($19.2) million for the six months ended June 30, 2010 compared to ($32.2) million for the same period in 2009. The Company recorded ($1.3) million of the total expenditures related to the February 2010 wind storm as capital spending and the remaining ($5.9) of expenditures have been deferred as a regulatory asset for future recovery in rates. Capital spending in the same period of 2009 included ($7.5) million related to the December 2008 ice storm and ($6.1) million of acquisition costs related to the acquisition of Northern Utilities and Granite. All other capital spending in the first six months of 2010 was ($17.9) million compared to ($18.6) million in the same period of 2009. Capital expenditures are projected to be approximately ($64.0) million in 2010 and ($60.0) million in 2011, reflecting normal electric and gas utility system additions.

	Six Months Ended June 30,	
	2010	2009
Cash (Used in) Financing Activities	**$ (9.2)**	$ (22.5)

Cash Provided by (Used in) Financing Activities – Cash Provided by (Used in) Financing Activities was ($9.2) million in the six months ended June 30, 2010 compared to ($22.5) million for the same period in 2009. In March 2010, Unitil Energy and Northern Utilities closed long-term debt financings of $15.0 million and $25.0 million, respectively. The net proceeds of these financings were used to refinance short-term borrowings. Short-term borrowings were reduced by ($39.9) million in the first six months of 2010. Other uses of cash include ($7.6) million for quarterly dividend payments and ($1.6) million related to gas inventory financing. Proceeds from issuances of common stock provided a source of cash of $0.5 million, and all other uses of cash were ($0.3) million.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 10, 2010.

Regulatory Accounting – The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)

	June 30, 2010	June 30, 2009	December 31, 2009
Energy Supply Contract Obligations	**$ 27.8**	$ 42.8	$ 34.7
Deferred Restructuring Costs	**26.9**	27.5	28.3
Generation-related Assets	**—**	0.4	—
Subtotal – Restructuring Related Items	**54.7**	70.7	63.0
Retirement Benefit Obligations	**43.7**	46.2	43.7
Income Taxes	**13.3**	15.3	14.5
Environmental Obligations	**21.2**	21.9	22.7
Deferred Storm Charges	**21.7**	12.5	14.6
Other	**8.7**	10.4	7.9
Total Regulatory Assets	**$163.3**	$177.0	$ 166.4
Less: Current Portion of Regulatory Assets(1)	**16.6**	24.0	21.9
Regulatory Assets – noncurrent	**$146.7**	$153.0	$ 144.5

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Utility Revenue Recognition – Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts – The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations – The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2009 and 2008, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000 and $200,000, respectively, in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2009 and 2008, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $735,000 and $675,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $576,000 and $531,000, respectively. See Note 8 to the accompanying Consolidated Financial Statements.

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets.

Depreciation – Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies – The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of June 30, 2010, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

As of June 30, 2010, the Company and its subsidiaries had 431 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of June 30, 2010, 147 of the Company’s employees were represented by labor unions. These employees are covered by four separate collective bargaining agreements which expire on March 31, 2012, May 31, 2012, May 31, 2013 and June 5, 2014. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rates on the Company’s short-term borrowings for the three months ended June 30, 2010 and June 30, 2009 were 2.33% and 4.28%, respectively. The average interest rates on the Company’s short-term borrowings for the six months ended June 30, 2010 and June 30, 2009 were 2.28% and 4.53%, respectively.

MARKET RISK

Although Unitil’s three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. *Financial Statements*

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating Revenues				
Gas	**$ 23.7**	$ 23.4	**$ 84.8**	$ 95.8
Electric	**46.6**	47.0	**97.4**	109.1
Other	**1.1**	1.1	**2.2**	2.2
Total Operating Revenues	**71.4**	71.5	**184.4**	207.1
Operating Expenses				
Purchased Gas	**14.3**	11.8	**52.6**	60.2
Purchased Electricity	**31.7**	33.4	**67.5**	80.6
Operation and Maintenance	**11.6**	12.0	**23.8**	22.4
Conservation & Load Management	**2.5**	1.4	**4.2**	2.5
Depreciation and Amortization	**7.1**	6.4	**14.2**	12.7
Provisions (Benefit) for Taxes:				
Local Property and Other	**2.5**	2.2	**5.6**	5.2
Federal and State Income	**(1.0)**	0.1	**2.9**	5.4
Total Operating Expenses	**68.7**	67.3	**170.8**	189.0
Operating Income	**2.7**	4.2	**13.6**	18.1
Non-Operating Expenses (Income)	**0.2**	0.2	**0.3**	0.2
Income Before Interest Expense	**2.5**	4.0	**13.3**	17.9
Interest Expense, Net	**4.5**	3.7	**8.8**	8.5
Net Income (Loss)	**(2.0)**	0.3	**4.5**	9.4
Less: Dividends on Preferred Stock	**0.1**	0.1	**0.1**	0.1
Earnings (Loss) Applicable to Common Shareholders	**$ (2.1)**	$ 0.2	**$ 4.4**	$ 9.3
Weighted Average Common Shares Outstanding – Basic (000's)	**10,820**	9,014	**10,810**	8,516
Weighted Average Common Shares Outstanding – Diluted (000's)	**10,820**	9,014	**10,811**	8,516
Earnings Per Common Share (Basic and Diluted)	**$ (0.19)**	$ 0.03	**$ 0.41**	$ 1.10
Dividends Declared Per Share of Common Stock	**$ 0.345**	$0.345	**$ 1.035**	$1.035

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)
(UNAUDITED)

	June 30, 2010	June 30, 2009	December 31, 2009
ASSETS:			
Utility Plant:			
Electric	**$310.7**	$294.1	$ 302.3
Gas	**330.2**	314.5	325.5
Common	**29.7**	27.8	28.9
Construction Work in Progress	**29.0**	13.4	26.0
Total Utility Plant	**699.6**	649.8	682.7
Less: Accumulated Depreciation	**243.0**	223.0	233.0
Net Utility Plant	**456.6**	426.8	449.7
Current Assets:			
Cash	**6.3**	10.3	7.7
Accounts Receivable – Net of Allowance for Doubtful Accounts of $3.0, $2.8 and $2.5	**27.9**	30.9	33.5
Accrued Revenue	**22.5**	31.0	44.0
Gas Inventory	**11.1**	8.5	14.3
Materials and Supplies	**3.4**	3.0	2.6
Prepayments and Other	**4.5**	4.1	4.7
Total Current Assets	**75.7**	87.8	106.8
Noncurrent Assets:			
Regulatory Assets	**146.7**	153.0	144.5
Other Noncurrent Assets	**26.6**	26.9	24.2
Total Noncurrent Assets	**173.3**	179.9	168.7
TOTAL	**$705.6**	$694.5	$ 725.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) June 30, 2010	(UNAUDITED) June 30, 2009	December 31, 2009
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$187.0**	$195.9	$ 193.1
Preferred Stock	**2.0**	2.0	2.0
Long-Term Debt, Less Current Portion	**288.6**	249.1	248.9
Total Capitalization	**477.6**	447.0	444.0
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.4	0.4
Accounts Payable	**16.7**	19.1	25.1
Short-Term Debt	**24.6**	30.6	64.5
Energy Supply Contract Obligations	**19.1**	18.1	23.1
Other Current Liabilities	**24.6**	32.9	16.6
Total Current Liabilities	**85.4**	101.1	129.7
Deferred Income Taxes	**33.6**	29.8	39.8
Noncurrent Liabilities:			
Energy Supply Contract Obligations	**17.1**	27.7	21.7
Retirement Benefit Obligations	**67.3**	71.1	65.5
Environmental Obligations	**14.3**	11.4	14.3
Other Noncurrent Liabilities	**10.3**	6.4	10.2
Total Noncurrent Liabilities	**109.0**	116.6	111.7
TOTAL	**$705.6**	$694.5	$ 725.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating Activities:		
Net Income	**$ 4.5**	$ 9.4
Adjustments to Reconcile Net Income to Cash		
Provided by Operating Activities:		
Depreciation and Amortization	**14.2**	12.7
Deferred Tax Provision	**(5.3)**	(2.6)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**5.6**	8.8
Accrued Revenue	**21.5**	25.9
Gas Inventory	**3.2**	23.1
Accounts Payable	**(8.4)**	(9.4)
All other Current Assets and Liabilities	**0.4**	(6.2)
Deferred Regulatory and Other Charges	**(5.1)**	(12.2)
Other, net	**(3.6)**	4.0
Cash Provided by Operating Activities	**27.0**	53.5
Investing Activities:		
Property, Plant and Equipment Additions	**(19.2)**	(26.1)
Acquisition Costs	**—**	(6.1)
Cash (Used in) Investing Activities	**(19.2)**	(32.2)
Financing Activities:		
Repayment of Short-Term Debt	**(39.9)**	(43.5)
Proceeds From Issuance (Repayment of) Long-Term Debt, net	**39.7**	(0.2)
Net Decrease in Gas Inventory Financing	**(1.6)**	(28.7)
Dividends Paid	**(7.6)**	(5.6)
Proceeds from Issuance of Common Stock, net	**0.5**	56.2
Other, net	**(0.3)**	(0.7)
Cash (Used in) Financing Activities	**(9.2)**	(22.5)
Net Decrease in Cash	**(1.4)**	(1.2)
Cash at Beginning of Period	**7.7**	11.5
Cash at End of Period	**$ 6.3**	$ 10.3
Supplemental Cash Flow Information:		
Interest Paid	**$ 9.7**	$ 9.7
Income Taxes Paid	**$ 1.0**	$ 0.5

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the "Acquisitions"). The final purchase price allocation is disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on February 10, 2010.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern and central Maine and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the distribution utilities).

Granite is a natural gas transportation pipeline, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third –party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service; Unitil Realty; and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and six months ended June 30, 2010 are not necessarily indicative of results to be expected for the year ending December 31, 2010. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission (SEC) on February 10, 2010, for a description of the Company's Basis of Presentation.

Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the Acquisition. As a result of the Acquisition and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisition and stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Accounting Codification – In June 2009, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 168). SFAS No. 168 was effective for financial statements for interim and annual periods ending after September 15, 2009. The Company has adopted SFAS No. 168 and therefore all references by the Company to authoritative accounting principles recognized by the FASB reflect the FASB Codification.

Derivatives – The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases natural gas futures contracts on the New York Mercantile Exchange (NYMEX) that correspond to the associated delivery month. Any gains or losses resulting from the change in the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company records gains and losses resulting from the change in fair value of the derivatives as regulatory liabilities or assets, then reclassifies these gains or losses into Purchased Gas when the gains and losses are passed through to customers in accordance with rate reconciling mechanisms.

As of June 30, 2010 and December 31, 2009, the Company had 1.3 billion and 1.9 billion cubic feet (BCF), respectively, outstanding in natural gas purchase contracts under its hedging program.

Liability Derivatives ($ millions)

The tables below show derivatives that are not designated as hedging instruments, under FASB ASC 815-20. As discussed above, the change in fair value related to these derivatives is recorded initially as a Regulatory Asset then reclassified to Purchased Gas in accordance with the recovery mechanism. The tables below include disclosure of the Regulatory Asset and reclassifications from the Regulatory Asset into Purchased Gas.

	As of					
	June 30, 2010		June 30, 2009		December 31, 2009	
Description	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Natural Gas Futures Contracts	Other Current Liabilities	$ 1.2	Other Current Liabilities	$ 5.5	Other Current Liabilities	$ 2.2
Natural Gas Futures Contracts	Other Noncurrent Liabilities	0.1	Other Noncurrent Liabilities	—	Other Noncurrent Liabilities	0.1
Total		$ 1.3		$ 5.5		$ 2.3

Regulatory Approved Hedging Programs	Amount of Loss Recognized in Regulatory Assets for Derivatives	
	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Natural Gas Futures Contracts	$ 1.0	$ 2.9
	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Natural Gas Futures Contracts	$ 1.4	$ 5.6

Location of Loss Reclassified into the Consolidated Statements of Earnings from Regulatory Assets	Amount of Loss Reclassified into the Consolidated Statements of Earnings from Regulatory Assets[1]	
	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Purchased Gas	$ 1.6	$ 3.9
	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Purchased Gas	$ 2.8	$ 5.8

(1) These amounts are offset in the Consolidated Statements of Earnings with Accrued Revenue and therefore there is no effect on earnings.

Subsequent Events – The Company has evaluated all events or transactions through the date of this filing. During this period, the Company did not have any material subsequent events that impacted its consolidated financial statements.

Reclassifications – Certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation.

Recently Issued Pronouncements – There are no recently issued pronouncements that the Company has not already adopted.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
06/17/10	08/16/10	08/02/10	$ 0.345
03/25/10	05/14/10	04/30/10	$ 0.345
01/14/10	02/16/10	02/02/10	$ 0.345
09/23/09	11/16/09	11/02/09	$ 0.345
06/18/09	08/14/09	07/31/09	$ 0.345
03/26/09	05/15/09	05/01/09	$ 0.345
01/15/09	02/16/09	02/02/09	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

Common Stock

The Company's common stock trades under the symbol "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the number of authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 10,869,603, 10,816,312 and 10,836,759 of common shares outstanding at June 30, 2010, June 30, 2009 and December 31, 2009, respectively.

Unitil Corporation Common Stock Offering – Between December 2008 and June 2009, the Company sold 4,970,000 shares of its common stock at a price of $20.00 per share in registered public offerings. The Company used the net proceeds of $93.1 million from these offerings primarily to complete the acquisition of Northern Utilities and Granite. Please see Note 3 to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2009 as filed with the SEC on February 10, 2010 for additional information.

Dividend Reinvestment and Stock Purchase Plan – During the first six months of 2010, the Company sold 20,639 shares of its Common Stock, at an average price of $21.80 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $450,000 were used to reduce short-term borrowings.

During the first six months of 2009, the Company sold 22,435 shares of its Common Stock, at an average price of $20.72 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $465,000 were used to reduce short-term borrowings.

Restricted Stock Plan – The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 5, 2010, 12,520 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $262,920. There were 37,797 and 44,602 non-vested shares under the Plan as of June 30, 2010 and 2009, respectively. The weighted average grant date fair value of these shares was $22.03 and $22.98, respectively. The compensation expense associated with the issuance of shares under the Plan is being recognized over the vesting period and was $0.3 million and $0.3 million for the six months ended June 30, 2010 and 2009, respectively. At June 30, 2010, there was approximately $1.0 million of total unrecognized compensation cost under the Plan which is expected to be recognized over approximately 2.7 years. There were 315 restricted shares forfeited under the Plan during the six months ended June 30, 2010. There were no cancellations under the Plan during the six months ended June 30, 2010.

Preferred Stock

Details on preferred stock at June 30, 2010, June 30, 2009 and December 31, 2009 are shown below:

(Amounts in Millions)

	June 30, 2010	June 30, 2009	December 31, 2009
Preferred Stock			
Unitil Energy Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$0.2**	$0.2	$ 0.2
Fitchburg Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.8	0.8
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$2.0**	$2.0	$ 2.0

NOTE 4 – LONG-TERM DEBT, CREDIT ARRANGEMENTS AND GUARANTEES

Long-Term Debt

Details on long-term debt at June 30, 2010, June 30, 2009 and December 31, 2009 are shown below ($ Millions):

	June 30, 2010	June 30, 2009	December 31, 2009
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
5.24% Series, Due March 2, 2020	**15.0**	—	—
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Northern Utilities Senior Notes:			
6.95% Senior Notes, Due December 3, 2018	**30.0**	30.0	30.0
5.29% Senior Notes, Due March 2, 2020	**25.0**	—	—
7.72% Senior Notes, Due December 3, 2038	**50.0**	50.0	50.0
Granite Senior Notes:			
7.15% Senior Notes, Due December 15, 2018	**10.0**	10.0	10.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due Through August 1, 2017	**4.0**	4.5	4.3
Total Long-Term Debt	**289.0**	249.5	249.3
Less: Current Portion	**0.4**	0.4	0.4
Total Long-term Debt, Less Current Portion	**$288.6**	$249.1	$ 248.9

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at June 30, 2010 is estimated to be approximately $311 million, before considering any costs, including prepayment costs, which generally require a "make-whole" payment, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

On March 2, 2010, Unitil Energy completed the sale of $15 million of First Mortgage Bonds through a private placement to institutional investors. The First Mortgage Bonds have a maturity of ten years and a coupon rate of

5.24%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On March 2, 2010, Northern Utilities completed the sale of $25 million of Senior Unsecured Notes through a private placement to institutional investors. The Senior Unsecured Notes have a maturity of ten years and a coupon rate of 5.29%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

Credit Arrangements

At June 30, 2010, the Company had $24.6 million in short-term debt outstanding through bank borrowings under its revolving credit facility. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit long-term debt to exceed 65% of capitalization at the end of each fiscal quarter. As of June 30, 2010, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 13, 2009, the Company entered into an amendment to its 364-day revolving credit facility with Bank of America, as administrative agent, and a syndicate of lenders. The Company originally entered into the facility on November 26, 2008. The amendment increased the maximum borrowings under the facility from $60 million to $80 million.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $8.5 million, $3.1 million and $10.0 million outstanding at June 30, 2010, June 30, 2009 and December 31, 2009, respectively, related to these asset management agreements.

Guarantees

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of June 30, 2010 there are $40.8 million of guarantees outstanding and the longest of these guarantees extends through October 31, 2011. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage Agreement discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite. As of June 30, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $4.0 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite notes due 2018. As of June 30, 2010, the principal amount outstanding for the 7.15% Granite notes was $10.0 million. This guarantee will terminate if Granite reorganizes and merges with and into Northern Utilities.

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and six months ended June 30, 2010 and June 30, 2009 (Millions):

Three Months Ended June 30, 2010	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$ 46.6**	**$ 23.7**	**$—**	**$ 1.1**	**$ 71.4**
Segment Profit (Loss)	**0.7**	**(3.1)**	**—**	**0.3**	**(2.1)**
Capital Expenditures	**1.0**	**7.5**	**0.4**	**—**	**8.9**
Three Months Ended June 30, 2009					
Revenues	$ 47.0	$ 23.4	$—	$ 1.1	$ 71.5
Segment Profit (Loss)	(0.2)	(0.5)	0.5	0.4	0.2
Capital Expenditures	1.8	6.3	—	—	8.1
Six Months Ended June 30, 2010					
Revenues	**$ 97.4**	**$ 84.8**	**$—**	**$ 2.2**	**$184.4**
Segment Profit (Loss)	**2.0**	**1.5**	**0.2**	**0.7**	**4.4**
Capital Expenditures	**7.9**	**10.3**	**1.0**	**—**	**19.2**
Segment Assets	**352.1**	**341.4**	**8.1**	**4.0**	**705.6**
Six Months Ended June 30, 2009					
Revenues	$109.1	$ 95.8	$—	$ 2.2	$207.1
Segment Profit (Loss)	1.3	7.1	0.1	0.8	9.3
Capital Expenditures	15.1	10.9	0.1	—	26.1
Segment Assets	345.1	338.9	8.1	2.4	694.5

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2009 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 10, 2010.

Legal Proceedings

A putative class action Complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009 an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2010. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Regulatory Matters

Unitil Energy Rate Case Filing – On April 15, 2010 Unitil Energy filed a proposed base rate increase of $10.1 million which represents an increase of 6.5 percent above present rates. Unitil Energy requested temporary rates to be effective July 1, 2010. In addition, Unitil Energy requested adjustments for a Rate Year Step Adjustment, a Large Capital Project Step Adjustment and a long-term rate plan establishing step adjustments associated with the Company's Reliability Enhancement Plan and Vegetation Management Plan. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy. The order provides for a temporary rate increase of $5.2 million (annual) effective July 1, 2010 which will be collected by applying a uniform per kilowatt-hour (kWh) surcharge of $0.00438 to each of Unitil Energy's current rate schedules. Of the $5.2 million rate increase, $500,000 of the increase is intended to permit Unitil Energy to annually recover expenses incurred during the December 2008 ice storm and another $500,000 of the increase is intended to fund higher planned vegetation management program expenditures. Once permanent rates are approved by the NHPUC, they will be reconciled to the date temporary rates were ordered, July 1, 2010. Final review and approval by the NHPUC of Unitil Energy's permanent base rate increase request is scheduled to be completed by February 2011.

Major Ice Storm – On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region. The Company spent approximately $24.0 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.3 million related to capital construction and $15.8 million, including carrying charges, which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

The MDPU conducted an investigation of Fitchburg's preparation for and response to the December 2008 Ice Storm during the first half of 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service, and ordered several remedial actions. First, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices. The management audit is expected to begin in the third quarter of 2010, subject to the selection of the audit firm by the MDPU from a list of qualified bidders who responded to an RFP issued by Fitchburg. Second, the MDPU directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. All of these operational and capital improvements have either been completed or are currently underway, and remain subject to MDPU review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

On July 28, 2009, Fitchburg filed with the MDPU a petition for approval to defer and record as a regulatory asset costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. On December 30, 2009, the MDPU approved the request. The order of approval made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. As of June 30, 2010, Fitchburg has deferred approximately $13.5 million, including carrying charges, associated with the repair of its electric distribution system for future recovery in rates.

On August 26, 2009, Unitil Energy filed a petition with the NHPUC requesting an accounting order authorizing Unitil Energy to record as a regulatory asset costs associated with electric distribution system damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's next base rate case. On November 9, 2009, the NHPUC granted the requested accounting order, clarifying that such issues as the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are issues that are appropriate for review in Unitil Energy's rate case. As of June 30, 2010, Unitil Energy has deferred approximately $2.3 million, including carrying charges, associated with the repair of its electric distribution system for future recovery in rates.

On December 3, 2009, the NHPUC issued its “After-Action” report regarding its review of the December 2008 Ice Storm. The report stated that the NHPUC will commence an adjudicative proceeding to examine the reasonableness of Unitil’s response to the December 2008 Ice Storm. On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy’s response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. This matter remains pending.

Fitchburg – Electric Operations – On November 25, 2009, Fitchburg submitted to the MDPU its annual (2009) reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). The rates were approved effective January 1, 2010, subject to reconciliation pending further investigation by the MDPU. This matter remains pending. A final order approving Fitchburg’s 2008 Annual Reconciliation Filing was issued on April 12, 2010.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility’s failure to comply with the MDPU’s regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU’s standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting regulations concerning the items required by House Bill 4329. Fitchburg has complied with the requirements concerning the filing of its emergency response plans and has met with MDPU Staff to review them.

Fitchburg – Gas Operations – On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU’s prior approval and that Fitchburg’s gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU’s order. On November 30, 2009, the MDPU approved Fitchburg’s proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement Order to the Massachusetts Supreme Judicial Court. Fitchburg believes that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

During the summer of 2009, Fitchburg operated its gas system entirely on local production from LNG for approximately three months due to construction on the lateral from Tennessee Gas Pipeline, which is the sole source of pipeline gas to Fitchburg. During this time Fitchburg provided gas LNG supply to all firm sales customers and also to the retail marketers for delivery to firm customers who have contracted for third party supply. Fitchburg’s management of this project was reviewed by the MDPU during its last Integrated Resource Plan proceeding, before the shutdown occurred. In its order, the MDPU stated it would investigate the costs associated with the shutdown in Fitchburg’s March 2010 Cost of Gas Adjustment (CGA) Clause filing when its actual costs will be reconciled with its projected costs. The Company received some data requests on the subject in the CGA proceeding, but no further investigation was necessary and the proposed CGA rates were approved as filed.

Fitchburg – Other – On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for Revenue Decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, through company-specific rate cases. Revenue decoupling is generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility’s distribution revenues on sales, and is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. It is anticipated that, with limited exceptions, all distribution companies will be operating under decoupling plans by year-end 2012.

On February 11, 2009, the Massachusetts Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, special tariffs to allow the net metering of customer-owned renewable generation, and terms and conditions for purchasing supplier receivables. Three year energy efficiency investment plans, plans to establish smart grid pilot programs, and net metering tariffs have been approved by the MDPU. Proposals to purchase long-term contracts for renewable energy and terms and conditions for purchasing supplier receivables are under review in a separately designated docket.

Unitil Energy – Other – In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources. An order approving a settlement agreement for a time-of-use pilot program was issued on February 26, 2010. On June 11, 2010, the NHPUC issued an order on the remaining two proposed projects and cost recovery. The NHPUC denied one of the two projects, citing that the costs outweighed the benefits but found the other project to be in the public interest. Unitil Energy may also file step adjustments to base distribution rates to collect actual costs associated with authorized DER projects. Recovery of ongoing program management and reporting costs was not allowed at this time, however.

On February 25, 2010, a significant wind storm struck portions of the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including approximately 85% of the Company's customers. Unitil Energy was able to restore power to 96% percent of its customers by day three, and its final customers, including those with individual service problems, were restored by day four. The Company spent approximately $7.2 million for the repair and replacement of electric distribution systems damaged during the storm, including $1.3 million related to capital construction and $5.9 million which has been deferred as a regulatory asset. Unitil Energy, in its base rate case filing discussed above, has requested recovery in rates for the costs associated with the emergency repair of its electric distribution system for damage caused by this storm. The amount and timing of the cost recovery of the storm restoration expenditures will be determined in the base rate case proceeding. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

On June 17, 2010, Unitil Energy made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2010, including reconciliation of prior year costs and revenues. This matter remains pending.

Northern Utilities – On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation ("NOPVs") of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern's distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at June 30, 2010 was $2.3 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in portions of Northern Utilities' Maine service areas. An Agreement resolving this matter, filed on behalf of Northern Utilities, the Maine Office of the Public Advocate, and several state legislator intervenors, was filed with the MPUC on July 6, 2010. Under the Agreement, Northern Utilities will proceed with a comprehensive upgrade and replacement program (the "Program"), which will provide for the systematic replacement of cast iron, wrought iron and bare steel pipe in Northern Utilities' natural gas distribution system in Portland and Westbrook, Maine and the conversion of the system to intermediate pressure. The Agreement establishes the objective of completing the Program by the end of the 2024 construction season. Under the Agreement, the parties agreed to support a cost recovery mechanism that will provide for the timely recovery of prudently-incurred costs of the Program. The features of this cost recovery mechanism will be finalized during Northern Utilities' next base rate case proceeding, which is anticipated to be filed in early 2011. On July 7, 2010, the MPUC considered the Agreement during its public deliberation session and voted to approve the Agreement. A written final order of approval has not yet been issued and, as a result, the matter remains pending.

Granite State Gas Transmission, Inc. – Base Rate Case Filing – On June 29, 2010, Granite filed a base transportation rate increase which would provide for an increase of approximately $3 million in annual revenue with the FERC. This represents Granite's first filing for a rate change since its last general rate case in 1997. The effect of this rate increase would result in an approximate increase of two percent in the total annual bill to an average residential natural gas heating customer served by Northern Utilities. The rate case filing reflects a rate base of $18.3 million, which includes $4.2 million of capital additions to be made through the end of 2010. In addition to its request for new base transportation rates, Granite is seeking FERC approval to implement a capital cost surcharge that would allow Granite to implement a rate surcharge annually to recover projected capital expenditures of approximately $12.7 million during the three-year time period 2011-2013. Granite expects the FERC regulatory process to take approximately six months with a rate order near the beginning of 2011.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2009 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 10, 2010.

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of June 30, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included in Environmental Obligations on the Company's Consolidated Balance Sheet at June 30, 2010 are accrued liabilities totaling $12.0 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties. Also included in Environmental Obligations on the Company's Consolidated Balance Sheet at June 30, 2010 are accrued liabilities totaling $2.3 million associated with Northern Utilities' environmental remediation obligations for former MGP sites. In addition to the amounts noted above, there are $0.2 million of accrued liabilities in Other Current Liabilities on the Company's Consolidated Balance Sheet at June 30, 2010 associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the recovery of these environmental remediation costs is probable through the regulatory process.

NOTE 8 – INCOME TAXES

The Company bills its customers sales tax in Massachusetts and Maine and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2009 and for the current interim reporting period ended June 30, 2010 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by the FASB Codification is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2006; December 31, 2007; and December 31, 2008. Income tax filings for the year ended December 31, 2009 have been extended until September 15, 2010. In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized net operating loss (NOL) carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of $5.0 million and $6.7 million, respectively. These NOL carrybacks resulted in a refund to the Company of $4.0 million which was received in November 2009. According to Internal Revenue Code rules, NOL refunds in excess of $2.0 million fall under the jurisdiction of the Joint Committee of Congress (Joint Committee) and are subject to review by the Internal Revenue Service (IRS) and attorneys of the Joint Committee. As a result, on December 30, 2009, the Company received notice that its Federal Income Tax return filings for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 are under examination by the IRS. The IRS is currently performing fieldwork as part of their audit procedures. Currently, the Company believes that the ultimate resolution of this examination will not result in a material adverse effect to the Company's financial position or results of operations.

NOTE 9 – RETIREMENT BENEFIT OBLIGATIONS

The Company co-sponsors the Unitil Corporation Retirement Plan (Pension Plan), the Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan), and the Unitil Corporation Supplemental Executive Retirement Plan (SERP) to provide certain pension and postretirement benefits for its retirees and current employees. Please see Note 9 to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2009 as filed with the SEC on February 10, 2010 for additional information regarding these plans.

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

	2010	2009
Used to Determine Plan Costs		
Discount Rate	**5.75%**	6.25%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017

The following tables provide the components of the Company's Retirement plan costs ($000's):

Three Months Ended June 30,	Pension Plan 2010	Pension Plan 2009	PBOP Plan 2010	PBOP Plan 2009	SERP 2010	SERP 2009
Service Cost	**$ 652**	$ 571	**$ 366**	$ 357	**$ 71**	$ 54
Interest Cost	**1,115**	1,074	**504**	579	**57**	45
Expected Return on Plan Assets	**(1,046)**	(1,108)	**(149)**	(89)	**—**	—
Prior Service Cost Amortization	**64**	66	**394**	428	**1**	(1)
Transition Obligation Amortization	**—**	—	**6**	5	**—**	—
Actuarial Loss Amortization	**602**	399	**—**	—	**33**	18
Sub-total	**1,387**	1,002	**1,121**	1,280	**162**	116
Amounts Capitalized and Deferred	**(481)**	(364)	**(237)**	(442)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 906**	$ 638	**$ 884**	$ 838	**$162**	$116

Six Months Ended June 30,	Pension Plan 2010	Pension Plan 2009	PBOP Plan 2010	PBOP Plan 2009	SERP 2010	SERP 2009
Service Cost	**$ 1,304**	$ 1,142	**$ 733**	$ 714	**$142**	$108
Interest Cost	**2,229**	2,147	**1,008**	1,157	**114**	90
Expected Return on Plan Assets	**(2,091)**	(2,216)	**(299)**	(178)	**—**	—
Prior Service Cost Amortization	**127**	132	**789**	856	**2**	(1)
Transition Obligation Amortization	**—**	—	**11**	10	**—**	—
Actuarial Loss Amortization	**1,203**	798	**—**	—	**66**	36
Sub-total	**2,772**	2,003	**2,242**	2,559	**324**	233
Amounts Capitalized and Deferred	**(1,103)**	(646)	**(587)**	(800)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 1,669**	$ 1,357	**$1,655**	$1,759	**$324**	$233

Employer Contributions

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92%—100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008—2010 plan years. This did not affect the Company's Pension Plan in 2009 as its Pension Plan was 94% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2008 and met the exemption from the shortfall amortization. As of June 30, 2010, the Company had made $1.8 million of contributions to the Pension Plan in 2010. The Company presently anticipates contributing an additional $2.7 million to fund its Pension Plan in 2010.

As of June 30, 2010, the Company had made $1.7 million and $26,000 of contributions to the PBOP and SERP Plans, respectively, in 2010. The Company presently anticipates contributing an additional $1.8 million and $27,000 to the PBOP and SERP Plans, respectively, in 2010.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in the Company's internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2009 as filed with the SEC on February 10, 2010.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended June 30, 2010.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 25, 2010, the Company will periodically repurchase shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. There is no pool or maximum number of shares related to these purchases; however, the trading plan will automatically terminate when $80,700 in value of shares have been purchased, or, if sooner, on March 25, 2011.

The Company may suspend or terminate this trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws.

The Company's repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
4/1/10 – 4/30/10	—	—	—
5/1/10 – 5/31/10	—	—	—
6/1/10 – 6/30/10	371	$ 19.91	371
Total	371	$ 19.91	371

Item 5. Other Information

On July 27, 2010, the Company issued a press release announcing its results of operations for the three- and six-month periods ended June 30, 2010. The press release is furnished with this Quarterly Report on Form 10-Q as Exhibit 99.1.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Weighted Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated July 27, 2010 Announcing Earnings For the Quarter Ended June 30, 2010.	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	UNITIL CORPORATION
	(Registrant)
Date: July 27, 2010	/s/ Mark H. Collin
	Mark H. Collin Chief Financial Officer
Date: July 27, 2010	/s/ Laurence M. Brock
	Laurence M. Brock Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Weighted Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated July 27, 2010 Announcing Earnings For the Quarter Ended June 30, 2010.	Filed herewith

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER WEIGHTED AVERAGE COMMON SHARE OUTSTANDING

(Millions except common shares and per share data)

(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Net Income (Loss)	**$ (2.0)**	**$ 0.3**	**$ 4.5**	$ 9.4
Less: Dividend Requirements on Preferred Stock	**0.1**	**0.1**	**0.1**	0.1
Net Income Applicable to Common Stock	**$ (2.1)**	**$ 0.2**	**$ 4.4**	$ 9.3
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**10,820**	**9,014**	**10,810**	8,516
Dilutive Effect of Stock Options and Restricted Stock (000's)	**—**	**—**	**1**	—
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**10,820**	**9,014**	**10,811**	8,516
Earnings Per Share – Basic and Diluted	**$ (0.19)**	**$ 0.03**	**$ 0.41**	$ 1.10

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 27, 2010

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 27, 2010

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 27, 2010

/s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	July 27, 2010
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	July 27, 2010
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	July 27, 2010

Exhibit 99.1

Contact: David Chong – Investor Relations
Phone: 603-773-6499
Email: chong@unitil.com

Alec O'Meara – Media Relations
Phone: 603-773-6404
Email: omeara@unitil.com

Unitil Reports Second Quarter Results

Hampton, NH – July 27, 2010: Unitil Corporation ("Company") (NYSE: UTL) (www.unitil.com) today announced a net loss of ($2.1) million for the second quarter of 2010, compared to earnings of $0.2 million for the second quarter of 2009. For the six months ended June 30, 2010, the Company reported net income of $4.4 million compared to $9.3 million for the same period of 2009. Results for the second quarter were driven primarily by higher depreciation and interest expense and lower gas sales margins due to warmer regional temperatures.

Earnings (loss) per common share (EPS) were ($0.19) and $0.41 for the three and six month periods ended June 30, 2010 compared with $0.03 and $1.10 for the same periods of 2009. The Company's results of operations for 2010 are not directly comparable with 2009 due to the issuance of 5.0 million common shares between December 2008 and June 2009 to complete the financing of the Company's acquisition of Northern Utilities Inc. (Northern Utilities) and Granite State Gas Transmission, Inc. (Granite), the ("Acquisition").

"2010 is an important transition year for the Company as we initiate the process of resetting rates in each of our regulatory jurisdictions," said Bob Schoenberger, Unitil's Chairman and Chief Executive Officer. "This regulatory agenda, which we expect to complete over the next twelve to eighteen months, will support our ongoing investment in the reliability and safety of our gas and electric distribution systems."

The Company filed two base rate cases in the second quarter of 2010, one for its New Hampshire electric distribution utility, Unitil Energy Systems, Inc. (Unitil Energy) and one for its natural gas pipeline subsidiary, Granite. The New Hampshire Public Utilities Commission has approved a temporary rate increase of $5.2 million on an annual basis, including recovery of 2008 ice storm costs, for Unitil Energy effective July 1, 2010. A decision from the Federal Energy Regulatory Commission on Granite's request for an increase of approximately $3 million in annual revenues is expected in January 2011. Additionally, the Company's two other distribution utilities, Fitchburg Gas and Electric Light Company and Northern Utilities, are currently preparing base rate cases and anticipate filing them with their respective regulatory commissions within the next year.

Natural gas sales margin decreased $2.4 million and $3.8 million in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009. Total natural gas therm sales were 5.1% and 6.0% lower in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of warmer temperatures in 2010, where there were approximately 22% and 12% fewer Heating Degree Days in the three and six month periods, respectively, compared to the prior year.

Electric sales margin increased $0.4 million and $0.1 million in the three and six months ended June 30, 2010 compared to the same periods in 2009, reflecting higher electric kilowatt-hour (kWh) sales. Total kWh sales increased 5.3% and 1.5% in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009 reflecting increased sales to all customer groups.

Selected Financial Data for 2010 and 2009 is presented in the following table:

Unitil Corporation – Condensed Financial Data

(Millions, except Per Share data)(Unaudited)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Gas Therm Sales:						
Residential	6.6	6.9	(4.3%)	24.4	26.2	(6.9%)
Commercial/Industrial	27.0	28.5	(5.3%)	81.6	86.6	(5.8%)
Total Gas Therm Sales	**33.6**	**35.4**	**(5.1%)**	**106.0**	**112.8**	**(6.0%)**
Electric kWh Sales:						
Residential	148.3	141.1	5.1%	326.0	321.7	1.3%
Commercial/Industrial	245.8	233.2	5.4%	483.3	475.3	1.7%
Total Electric kWh Sales	**394.1**	**374.3**	**5.3%**	**809.3**	**797.0**	**1.5%**
Gas Revenues	$ 23.7	$ 23.4	$ 0.3	$ 84.8	$ 95.8	$(11.0)
Purchased Gas	15.1	12.4	2.7	54.2	61.4	(7.2)
Gas Sales Margin	**8.6**	**11.0**	**(2.4)**	**30.6**	**34.4**	**(3.8)**
Electric Revenues	46.6	47.0	(0.4)	97.4	109.1	(11.7)
Purchased Electricity	33.4	34.2	(0.8)	70.1	81.9	(11.8)
Electric Sales Margin	**13.2**	**12.8**	**0.4**	**27.3**	**27.2**	**0.1**
Usource Sales Margin	**1.1**	**1.1**	**—**	**2.2**	**2.2**	**—**
Total Sales Margin:	**22.9**	**24.9**	**(2.0)**	**60.1**	**63.8**	**(3.7)**
Operation & Maintenance Expenses	11.6	12.0	(0.4)	23.8	22.4	1.4
Depreciation, Amortization, Taxes & Other	8.9	9.0	(0.1)	23.1	23.6	(0.5)
Interest Expense, Net	4.5	3.7	0.8	8.8	8.5	0.3
Earnings (Loss) Applicable to Common Shareholders:	**$ (2.1)**	**$ 0.2**	**$ (2.3)**	**$ 4.4**	**$ 9.3**	**$ (4.9)**
Earnings (Loss) Per Share	**$ (0.19)**	**$ 0.03**	**$ (0.22)**	**$ 0.41**	**$ 1.10**	**$(0.69)**

O&M expenses decreased $0.4 million and increased $1.4 million for the three and six months ended June 30, 2010, respectively, compared to 2009. The changes in O&M reflect higher utility operating costs and lower professional fees. The increases in utility operating expenses reflect the full integration of Northern Utilities and Granite State into the Company's consolidated operating results.

Depreciation and Amortization expense increased $0.7 million and $1.5 million in the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009 reflecting normal utility plant additions.

Interest Expense, Net increased $0.8 million and $0.3 million in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in the three and six month periods. Furthermore, net interest expense in 2010 reflects the permanent financing of Northern Utilities and Granite State, which was completed in the second quarter of 2009.

Federal and State Income Taxes decreased by $2.5 million due to lower pre-tax income in 2010 compared to 2009.

All other items increased $0.3 million and $0.5 million in the three and six month periods ended June 30, 2010, respectively, compared to the same periods in 2009, primarily reflecting higher property and payroll taxes.

Also in the second quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

Additionally, EPS in the three and six months ended June 30, 2010 reflect a higher number of average shares outstanding year over year. Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the Acquisition. As a result of the Acquisition and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisition and stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

The Company will hold a quarterly conference call to discuss second quarter 2010 results on Tuesday, July 27, 2010, at 2:00 p.m. Eastern Time. This call is being webcast by Thomson Financial and can be accessed in the Investor Relations section of Unitil Corporation's website, www.unitil.com.

About Unitil

Unitil Corporation is a public utility holding company headquartered in Hampton, New Hampshire. Unitil's principal business is the local distribution of electricity and natural gas in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three distribution utilities: (i) Unitil Energy Systems, Inc., which provides electric service in the southeastern seacoast and state capital regions of New Hampshire; (ii) Fitchburg Gas and Electric Light Company, which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and (iii) Northern Utilities, Inc., which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine. In addition, Unitil is the parent company of Granite State Gas Transmission, Inc., an interstate natural gas transmission pipeline in New Hampshire and Maine. Together, Unitil's operating utilities serve approximately 100,500 electric customers and 70,000, natural gas customers. Unitil's non-regulated business, Usource, also provides energy brokering and advisory services to large commercial and industrial customers in the northeastern United States.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended September 30, 2010

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	**(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 22, 2010
Common Stock, No par value	**10,881,062 Shares**

[Table of Contents](#)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended September 30, 2010

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company headquartered in Hampton, New Hampshire. Unitil is subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, Inc. (Northern Utilities), a natural gas distribution utility serving customers in New Hampshire and Maine, from Bay State Gas Company and (ii) all of the outstanding capital stock of Granite State Gas Transmission, Inc. (Granite), an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (the Acquisitions).

Unitil's principal business is the local distribution of electricity and natural gas throughout its service territory in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities:

i) Unitil Energy Systems, Inc. (Unitil Energy), which provides electric service in southeastern seacoast and state capital regions of New Hampshire;

ii) Fitchburg Gas and Electric Light Company (Fitchburg), which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and

iii) Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area.

Unitil Energy, Fitchburg and Northern Utilities are collectively referred to as the "distribution utilities." Together, the distribution utilities serve approximately 100,500 electric customers and 70,000 natural gas customers in their service territory.

In addition, Unitil is the parent company of Granite, a natural gas inter-state transmission pipeline, regulated by the FERC, operating 87 miles of underground gas transmission pipeline primarily located in Maine and New Hampshire. Granite provides Northern Utilities with interconnection to three major natural gas pipelines and access to pipeline supplies.

The distribution utilities are local "pipes and wires" operating companies and Unitil had an investment in Net Utility Plant of $463.6 million at September 30, 2010. Unitil's total operating revenue includes revenue to recover the approved cost of purchased electricity and natural gas in rates on a fully reconciling basis. As a result of this reconciling rate structure, the Company's earnings are not directly affected by changes in the cost of purchased electricity and natural gas. Earnings from Unitil's utility operations are primarily derived from the return on investment in the utility assets of the three distribution utilities and Granite.

Unitil also conducts non-regulated operations principally through Usource Inc. and Usource L.L.C. (collectively, "Usource"), which is wholly-owned by Unitil Resources Inc., a wholly-owned subsidiary of Unitil. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. The Company's other subsidiaries include Unitil Service Corp., which provides, at cost, a variety of administrative and professional services to Unitil's affiliated companies, Unitil Realty Corp., which owns and manages Unitil's corporate office building and property located in Hampton, New Hampshire and Unitil Power Corp., which formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

RATES AND REGULATION

Base Rate Cases:

On April 15, 2010, Unitil Energy filed a proposed annual base rate increase of $10.1 million with the New Hampshire Public Utilities Commission (NHPUC), which represents an increase of 6.5 percent above present rates. Unitil Energy's filing also included a long-term rate plan establishing base rate step adjustments associated with future planned capital additions and targeted reliability enhancement and vegetation management programs. In its rate filing, Unitil Energy requested that rates initially be set at a lower level on a temporary basis.

On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy. The order provides for a temporary rate increase of $5.2 million (annual) effective July 1, 2010 which will be collected by applying a uniform per kilowatt-hour (kWh) surcharge of $0.00438 to each of Unitil Energy's current rate schedules. Of the $5.2 million rate increase, $500,000 of the increase is intended to permit Unitil Energy to annually recover expenses incurred during the December 2008 ice storm and another $500,000 of the increase is intended to fund higher planned vegetation management program expenditures. Once permanent rates are approved by the NHPUC, they will be reconciled to the date temporary rates were ordered, July 1, 2010. Final review and approval by the NHPUC of Unitil Energy's permanent base rate increase request is currently scheduled to be completed by February 2011.

On June 29, 2010, Granite filed for an initial proposed base transportation rate increase with the FERC, which is Granite's first filing for a rate change since its last general rate case in 1997. If approved as filed, the initial rate increase would provide for an increase of approximately $2.3 million in revenue on an annual basis. In addition to its request for new base transportation rates, Granite, in its rate case filing, is seeking approval to implement a capital cost surcharge that would allow Granite to implement a rate surcharge annually to recover certain projected capital expenditures in future periods. Granite expects the FERC regulatory process to result in an effective date of January 1, 2011 for the requested rate increase.

Additionally, Fitchburg and Northern Utilities are currently preparing base rate cases and anticipate completing them with their respective state regulatory commissions within the next twelve months.

Regulation:

Unitil is subject to comprehensive regulation by federal and state regulatory authorities. Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Unitil's utility operations related to wholesale and interstate energy business activities are also regulated by FERC. Unitil's distribution utilities are subject to regulation by the applicable state public utility commissions, in regards to their rates, issuance of securities and other accounting and operational matters: Unitil Energy is subject to regulation by the NHPUC; Fitchburg is subject to regulation by the Massachusetts Department of Public Utilities (MDPU); and Northern Utilities is regulated by the NHPUC and the Maine Public Utilities Commission (MPUC). Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's distribution utilities deliver electricity and/or natural gas to all customers in their service territory, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil's distribution utilities recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in New Hampshire, Massachusetts and Maine, Unitil's customers have the opportunity to purchase their electricity or natural gas supplies from third party suppliers. A majority of Unitil's largest commercial and industrial (C&I) customers purchase their electric and natural gas supplies from third party suppliers. However, most residential and small customers continue to purchase their electric and natural gas supplies through Unitil's distribution utilities. Unitil's distribution utilities purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

Table of Contents

The regulatory process in both New Hampshire and Maine, in connection with those states' approvals of the Acquisitions, included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern Utilities' rates, customer service and operations. The settlement agreements were separately negotiated and filed in each state but reflect a number of common features. For additional discussion, please refer to Unitil's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 10, 2010.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include those described in Item 1A (Risk Factors) and the following:

- The Company's ability to achieve the estimated potential synergy savings attributable to the Acquisitions;
- The Company's ability to retain existing customers and gain new customers;
- Variations in weather;
- Major storms;
- Recovery of deferred major storm costs;
- Recovery of energy commodity costs;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions that could have an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of our counterparty obligations, including those of our insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended September 30, 2010 and September 30, 2009 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Part I, Item 1 of this report.

Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the Acquisitions. As a result of the Acquisitions and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisitions and stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Earnings Overview

The Company's Earnings (Loss) Applicable to Common Shareholders was a net loss of ($0.1) million for the third quarter of 2010, an improvement of $0.5 million compared to the third quarter of 2009. For the nine months ended September 30, 2010, the Company reported net income of $4.3 million compared to $8.7 million for the same period of 2009. Results for the third quarter were driven primarily by higher electric sales margins reflecting favorable summer weather and higher rates, partially offset by increases in operating and interest costs.

Earnings (loss) per common share (EPS) were ($0.01) and $0.40 for the three and nine month periods ended September 30, 2010 compared with ($0.06) and $0.94 for the same periods of 2009. The Company's results of operations for 2010 are not directly comparable with 2009 due to the issuance of 5.0 million common shares between December 2008 and June 2009 to complete the financing of the Company's acquisitions of Northern Utilities and Granite.

Natural gas sales margin was unchanged in the third quarter of 2010 compared to the same period in 2009. For the nine month period ended September 30, 2010, gas sales margin was $3.8 million lower compared to the same period in 2009. Total natural gas therm sales were 2.7% and 5.5% lower in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of warmer winter temperatures earlier in 2010, where there were approximately 13% fewer Heating Degree Days in the nine month period, compared to the prior year.

Electric sales margin increased $2.4 million and $2.5 million in the three and nine months ended September 30, 2010 compared to the same periods in 2009, reflecting higher electric kilowatt-hour (kWh) sales and an electric rate increase implemented in July 2010 for the Company's New Hampshire electric distribution utility. Total kWh sales increased 11.1% and 4.9% in the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009 reflecting increased sales to all customer groups. The increased sales reflect above average summer temperatures in the Company's utility service territories in 2010. According to ISO-New England, the grid operator for the New England region, July was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month.

Operation and Maintenance (O&M) expenses increased $1.1 million and $2.5 million for the three and nine months ended September 30, 2010, respectively, compared to 2009. The changes in O&M expenses reflect higher utility operating costs and professional fees. Utility operating expenses reflect the full integration of Northern Utilities and Granite into the Company's consolidated operating results.

Depreciation and Amortization expense decreased $0.4 million and increased $1.1 million in the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009, reflecting higher depreciation on normal utility plant additions partially offset by lower amortization expense in the current year.

Interest Expense, Net increased $0.7 million and $1.0 million in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in the three and nine month periods.

Federal and State Income Taxes decreased by $2.1 million for the nine month period due to lower pre-tax income in 2010 compared to 2009.

All other expenses increased $0.3 million and $0.8 million in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009, primarily reflecting higher property and payroll taxes.

Usource, our non-regulated energy brokering business, recorded revenues of $1.2 million and $3.4 million in the three and nine month periods ended September 30, 2010, respectively, increases of $0.2 million and $0.2 million, respectively compared to the same periods of 2009. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource.

Additionally, EPS for the nine months ended September 30, 2010 reflects a higher number of average shares outstanding year over year, as discussed above.

In 2009, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2010, March, 2010, June 2010 and September 2010 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three and nine months ended September 30, 2010 and a period-to-period comparison of changes in financial position are presented below.

Gas Sales, Revenues and Margin

Therm Sales – Total natural gas therm sales were 2.7% and 5.5% lower in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of milder winter temperatures earlier in 2010, where there were approximately 13% fewer Heating Degree Days in the nine month period, compared to the prior year.

The following table details total firm therm sales for the three and nine months ended September 30, 2010 and 2009, by major customer class:

Therm Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	2009	Change	% Change	2010	2009	Change	% Change
Residential	**2.5**	2.9	(0.4)	(13.8%)	**26.9**	29.1	(2.2)	(7.6%)
Commercial / Industrial	**19.3**	19.5	(0.2)	(1.0%)	**100.9**	106.1	(5.2)	(4.9%)
Total	**21.8**	22.4	(0.6)	(2.7%)	**127.8**	135.2	(7.4)	(5.5%)

Table of Contents

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and nine months ended September 30, 2010 and 2009:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	**2009**	**$ Change**	**% Change(1)**	**2010**	**2009**	**$ Change**	**% Change(1)**
Gas Operating Revenue:								
Residential	**$ 6.7**	$ 5.7	$ 1.0	6.6%	**$ 42.5**	$ 45.9	$ (3.4)	(3.1%)
Commercial / Industrial	**10.7**	9.5	1.2	7.9%	**59.7**	65.1	(5.4)	(4.8%)
Total Gas Operating Revenue	**$ 17.4**	$ 15.2	$ 2.2	14.5%	**$ 102.2**	$ 111.0	$ (8.8)	(7.9%)
Cost of Gas Sales:								
Purchased Gas	**$ 8.9**	$ 6.9	$ 2.0	13.2%	**$ 61.5**	$ 67.1	$ (5.6)	(5.0%)
Conservation & Load Management	**0.6**	0.4	0.2	1.3%	**2.2**	1.6	0.6	0.5%
Total Cost of Gas Sales	**$ 9.5**	$ 7.3	$ 2.2	14.5%	**$ 63.7**	$ 68.7	$ (5.0)	(4.5%)
Gas Sales Margin	**$ 7.9**	$ 7.9	$ —	—	**$ 38.5**	$ 42.3	$ (3.8)	(3.4%)

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $2.2 million, or 14.5%, and decreased $8.8 million, or 7.9%, in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. Total Gas Operating Revenues include the recovery of the approved cost of gas sales, which are recorded as Purchased Gas and Conservation & Load Management (C&LM) in Operating Expenses. The increase in Total Gas Operating Revenues in the third quarter of 2010 reflects higher Purchased Gas revenues of $2.0 million and higher C&LM revenues of $0.2 million. The decrease in Total Gas Operating Revenues in the first nine months of 2010 reflects lower Purchased Gas revenues of $5.6 million and lower gas sales margin of $3.8 million, partially offset by higher C&LM revenues of $0.6 million.

The Purchased Gas and C&LM components of Gas Operating Revenues increased a combined $2.2 million, or 14.5%, of Total Gas Operating Revenue and decreased a combined $5.0 million, or 4.5%, of Total Gas Operating Revenue in the three and nine month periods ended September 30, 2010 compared to the same periods in 2009. The increase in the third quarter of 2010 is due to higher natural gas commodity costs and increased spending on energy efficiency and conservation programs, partially offset by lower natural gas sales. The decrease in the nine month period of 2010 primarily reflects lower sales of natural gas, partially offset by increased spending on energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin was unchanged in the third quarter of 2010 compared to the same period in 2009. For the nine month period ended September 30, 2010, gas sales margin was $3.8 million lower compared to the same period in 2009. The decrease in the nine month period principally reflects lower sales of natural gas, which reflect the effect of the milder winter heating season.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Total electric kWh sales increased 11.1% and 4.9% in the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009 reflecting increased sales to all customer groups. The increased sales reflect higher than average summer temperatures in the Company's utility service territories in 2010 where there were approximately 61% more Cooling

Degree Days in the three month period ended September 30, 2010, compared to the prior year. According to ISO-New England, the grid operator for the New England region, July was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month.

The following table details total kWh sales for the three and nine months ended September 30, 2010 and 2009 by major customer class:

kWh Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	**2009**	**Change**	**% Change**	**2010**	**2009**	**Change**	**% Change**
Residential	**198.7**	172.1	26.6	15.5%	**524.7**	493.8	30.9	6.3%
Commercial / Industrial	**284.6**	263.0	21.6	8.2%	**767.9**	738.2	29.6	4.0%
Total	**483.3**	435.1	48.2	11.1%	**1,292.6**	1,232.1	60.5	4.9%

Electric Operating Revenues and Sales Margin – The following table details total Electric Operating Revenues and Sales Margin for the three and nine month periods ended September 30, 2010 and 2009:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	**2009**	**$ Change**	**% Change(1)**	**2010**	**2009**	**$ Change**	**% Change(1)**
Electric Operating Revenue:								
Residential	**$ 31.0**	$ 27.9	$ 3.1	5.7%	**$ 82.9**	$ 84.3	$ (1.4)	(0.9%)
Commercial / Industrial	**26.5**	26.3	0.2	0.4%	**72.0**	79.0	(7.0)	(4.3%)
Total Electric Operating Revenue	**$ 57.5**	$ 54.2	$ 3.3	6.1%	**$ 154.9**	$ 163.3	$ (8.4)	(5.2%)
Cost of Electric Sales:								
Purchased Electricity	**$ 39.6**	$ 38.9	$ 0.7	1.3%	**$ 107.1**	$ 119.5	$ (12.4)	(7.6%)
Conservation & Load Management	**1.0**	0.8	0.2	0.4%	**3.6**	2.1	1.5	0.9%
Total Cost of Electric Sales	**$ 40.6**	$ 39.7	$ 0.9	1.7%	**$ 110.7**	$ 121.6	$ (10.9)	(6.7%)
Electric Sales Margin	**$ 16.9**	$ 14.5	$ 2.4	4.4%	**$ 44.2**	$ 41.7	$ 2.5	1.5%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenue, increased by $3.3 million, or 6.1%, and decreased by $8.4 million, or 5.2%, in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. Total Electric Operating Revenues include the recovery of the approved cost of electric sales, which are recorded as Purchased Electricity and C&LM in Operating Expenses. The increase in Total Electric Operating Revenues in the third quarter of 2010 reflects higher Purchased Electricity revenues of $0.7 million, higher C&LM revenues of $0.2 million and higher electric sales margin of $2.4 million. The decrease in Total Electric Operating Revenues in the first nine months of 2010 reflects lower Purchased Electricity revenues of $12.4 million, partially offset by higher C&LM revenues of $1.5 million and higher electric sales margin of $2.5 million.

The Purchased Electricity and C&LM components of Total Electric Operating Revenues increased a combined $0.9 million, or 1.7%, and decreased a combined $10.9 million, or 6.7%, of Total Electric Operating Revenues in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. The increase in the three month period primarily reflects higher kWh sales in the current period. The decrease in the nine month period primarily reflects an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity costs, partially offset by higher spending on energy efficiency and conservation programs and increased sales. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $2.4 million and $2.5 million in the three and nine months ended September 30, 2010 compared to the same periods in 2009, reflecting higher electric kilowatt-hour (kWh) sales and higher rates, implemented in July 2010 for Unitil Energy Systems, Inc., the Company's New Hampshire electric distribution utility.

Operating Revenue - Other

The following table details total Other Revenue for the three and nine months ended September 30, 2010 and 2009:

Other Revenue (000's)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	**2009**	**$ Change**	**% Change**	**2010**	**2009**	**$ Change**	**% Change**
Other	**$ 1.2**	$ 1.0	$ 0.2	20.0%	**$ 3.4**	$ 3.2	$ 0.2	6.3%
Total Other Revenue	**$ 1.2**	$ 1.0	$ 0.2	20.0%	**$ 3.4**	$ 3.2	$ 0.2	6.3%

Total Other Revenue increased $0.2 million, or 20.0%, and $0.2 million, or 6.3%, in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. Other Revenues represents revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $2.0 million, or 29.0%, and decreased $5.6 million, or 8.4%, in the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009. The increase in the third quarter of 2010 is due to higher natural gas commodity costs partially offset by lower sales of natural gas. The decrease in the nine month period of 2010 primarily reflects lower sales of natural gas. The Company recovers the approved costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $0.7 million, or 1.8%, and decreased $12.4 million, or 10.4%, in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. The increase in the three month period primarily reflects increased sales in the current period. The decrease in the nine month period primarily reflects an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity costs, partially offset by increased sales. The Company recovers the approved costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expenses increased $1.1 million, or 9.2%, and $2.5 million, or 7.3%, for the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009. The changes in O&M expenses reflect higher utility operating costs and professional fees. Utility operating costs primarily consist of compensation and benefit costs, utility distribution and transmission system maintenance costs, bad debt expenses, office expenses and insurance costs. O&M expenses reflect the full integration of Northern Utilities and Granite State into the Company's consolidated operating results.

Conservation & Load Management – Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy usage. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 60% of these costs are related to electric operations and 40% to gas operations.

Total C&LM expenses increased $0.4 million, or 33.3% and $2.1 million, or 56.8%, in the three and nine month periods ended September 30, 2010 compared to the same periods in 2009. These approved costs are collected from customers on a pass through basis and therefore, fluctuations in program costs do not affect earnings.

Depreciation, Amortization and Taxes

Depreciation and Amortization – Depreciation and Amortization expense decreased $0.4 million, or 6.1%, and increased $1.1 million, or 5.7% in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009, reflecting higher depreciation on normal utility plant additions partially offset by lower amortization expense in the current year.

Local Property and Other Taxes – Local Property and Other Taxes increased $0.3 million and $0.7 million in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. These increases reflect higher local property tax rates on higher levels of utility plant in service and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes – Federal and State Income Taxes were higher by $0.4 million in the three month period ended September 30, 2010 compared to the same period in 2009 reflecting higher pre-tax earnings in the current period. For the nine month period ended September 30, 2010, Federal and State Income Taxes were lower by $2.1 million compared to the same period in 2009 reflecting lower pre-tax earnings in the current period.

Other Non-Operating Expenses (Income)

Other Non-Operating Expenses were on par in the three month period ended September 30, 2010 compared to the same period in 2009 and increased by $0.1 million in the nine month period ended September 30, 2010 compared to the same period in 2009.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. In addition, certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

Unitil's utility subsidiaries operate a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the distribution utilities' rate tariffs, interest is accrued on these balances and will produce either interest income or interest expense. Consistent with regulatory precedent, interest income is recorded on an under-collection of costs which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (Millions)	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Interest Expense						
Long-term Debt	**$ 5.1**	$ 4.5	$ 0.6	**$ 14.9**	$ 13.7	$ 1.2
Short-term Debt	**0.3**	0.5	(0.2)	**1.1**	1.6	(0.5)
Regulatory Liabilities	**0.1**	0.1	—	**0.2**	0.2	—
Subtotal Interest Expense	**5.5**	5.1	0.4	**16.2**	15.5	0.7
Interest (Income)						
Regulatory Assets	**(0.6)**	(0.6)	—	**(2.3)**	(1.9)	(0.4)
AFUDC[(1)] and Other	**(0.2)**	(0.5)	0.3	**(0.4)**	(1.1)	0.7
Subtotal Interest (Income)	**(0.8)**	(1.1)	0.3	**(2.7)**	(3.0)	0.3
Total Interest Expense, Net	**$ 4.7**	$ 4.0	$ 0.7	**$ 13.5**	$ 12.5	$ 1.0

(1) AFUDC – Allowance for Funds Used During Construction.

Interest Expense, Net increased $0.7 million and $1.0 million in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in the three and nine month periods.

On March 2, 2010, Unitil Energy completed the sale of $15 million of First Mortgage Bonds through a private placement to institutional investors. The First Mortgage Bonds have a maturity of ten years and a coupon rate of 5.24%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On March 2, 2010, Northern Utilities completed the sale of $25 million of Senior Unsecured Notes through a private placement to institutional investors. The Senior Unsecured Notes have a maturity of ten years and a coupon rate of 5.29%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities. The Company initially supplements internally-generated funds through bank borrowings, as needed, under its unsecured short-term bank credit facility. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets. The Company's utility operations are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

Unitil has a revolving credit facility with a group of banks that extends to October 8, 2013. The borrowing limit under the revolving credit facility is $80.0 million. There was $46.3 million and $64.5 million in short-term debt outstanding through bank borrowings under the revolving credit facility at September 30, 2010 and December 31, 2009, respectively. The total amount of credit available under the Company's revolving credit facility was $33.7 million and $15.5 million at September 30, 2010 and December 31, 2009, respectively. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter. As of September 30, 2010, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 8, 2010, the Company entered into the Fourth Amendment Agreement with Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto (the "Fourth Amendment Agreement"), further amending the credit agreement dated as of November 26, 2008 among Unitil, Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto. The credit agreement was previously amended on January 2, 2009, March 16, 2009, and October 13, 2009 to, among other things, increase the maximum borrowings under the facility to $80.0 million. The Fourth Amendment Agreement extends the scheduled termination date of the credit agreement to October 8, 2013 and provides for two conditional one-year extensions subsequent to the October 8, 2013 termination date (if agreed to among the lenders and Unitil). The Fourth Amendment Agreement also provides the Company a mechanism to request an increase in maximum borrowings of $20.0 million (in increments of not less than $5.0 million). The Fourth Amendment Agreement also provides a new letter of credit sub-facility pursuant to which up to $25.0 million of the credit agreement may be used for the purpose of issuing letters of credit for Unitil or its subsidiaries. Also, see Credit Arrangements in Note 4.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $12.3 million, $7.6 million and $10.0 million outstanding at September 30, 2010, September 30, 2009 and December 31, 2009, respectively, related to these asset management agreements.

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2010 there are $34.5 million of guarantees outstanding and the longest of these guarantees extends through February 29, 2012. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage agreement discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite. As of September 30, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $4.0 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite notes due 2018. As of September 30, 2010, the principal amount outstanding for the 7.15% Granite notes was $10.0 million.

Off-Balance Sheet Arrangements

The Company and its subsidiaries do not currently use, and are not dependent on the use of, off-balance sheet financing arrangements such as securitization of receivables or obtaining access to assets or cash through special purpose entities or variable interest entities. Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their vehicles, machinery and office equipment under both capital and operating lease arrangements.

Cash Flows

Unitil's utility operations, taken as a whole, are seasonal in nature and are therefore subject to seasonal fluctuations in cash flows. The tables below summarize the major sources and uses of cash (in millions) for the nine months ended September 30, 2010 compared to the same period in 2009.

	Nine Months Ended September 30,	
	2010	2009
Cash Provided by Operating Activities	**$ 21.5**	$ 45.4

Cash Provided by Operating Activities – Cash Provided by Operating Activities was $21.5 million for the first nine months of 2010 compared to $45.4 million in the same period of 2009. In the first nine months of 2010 as compared to the first nine months of 2009, net sources of cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes decreased by $9.3 million, changes in working capital items decreased $30.0 million, and changes in all other Operating Activities increased $15.4 million. A portion of the $30.0 million decrease in changes in working capital items resulted from a decrease in sources of cash from gas inventory of $19.4 million driven by changes in natural gas prices. The Company finances its gas inventory requirements with asset management agreements (see Credit Arrangements in Note 4), and reflects this activity in Cash Provided by Financing Activities.

	Nine Months Ended September 30,	
	2010	2009
Cash (Used in) Investing Activities	**$ (33.8)**	$ (49.8)

Cash (Used in) Investing Activities – Cash (Used in) Investing Activities was ($33.8) million for the nine months ended September 30, 2010 compared to ($49.8) million for the same period in 2009. In the first nine months of 2010, the Company recorded ($1.3) million in capital expenditures related to the February 2010 wind storm. Capital spending in the same period of 2009 included ($8.2) million related to the December 2008 ice storm and ($6.8) million of acquisition costs related to the acquisitions of Northern Utilities and Granite. All other remaining capital spending is representative of normal distribution utility capital expenditures and was ($32.5) million in the first nine months of 2010 compared to ($34.8) million compared to the same period of 2009. Capital expenditures are projected to be approximately ($55.0) million for 2010 and ($60.0) million for 2011, reflecting normal electric and gas utility system additions.

	Nine Months Ended September 30,	
	2010	2009
Cash Provided by Financing Activities	**$ 12.6**	$ 1.9

Cash Provided by Financing Activities – Cash Provided by Financing Activities was $12.6 million for the nine months ended September 30, 2010 compared to $1.9 million for the same period in 2009. In March 2010, Unitil Energy and Northern Utilities closed long-term debt financings of $15.0 million and $25.0 million, respectively. The net proceeds of $39.7 million from these financings were used to refinance short-term borrowings. Short-term borrowings were reduced by ($18.2) million in the first nine months of 2010. Other uses of cash include ($11.3) million for quarterly dividend payments compared to ($9.4) million for the same period in 2009. Proceeds from issuances of common stock and gas inventory financing provided a source of cash of $0.7 million and $2.3 million, respectively. All other uses of cash were ($0.6) million.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, the Company is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment, the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 10, 2010.

Regulatory Accounting – The Company's principal business is the distribution of electricity and natural gas by the three distribution utilities: Unitil Energy, Fitchburg and Northern Utilities. Unitil Energy and Fitchburg are subject to regulation by the FERC. Fitchburg is also regulated by the MDPU, Unitil Energy is regulated by the NHPUC and Northern Utilities is regulated by the MPUC and NHPUC. Granite, the Company's natural gas transmission pipeline, is regulated by the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

Regulatory Assets consist of the following (millions)

	September 30,		December 31,
	2010	**2009**	**2009**
Energy Supply Contract Obligations	**$ 24.3**	$ 38.1	$ 34.7
Deferred Restructuring Costs	**25.8**	27.7	28.3
Generation-related Assets	**—**	0.2	—
Subtotal – Restructuring Related Items	**50.1**	66.0	63.0
Retirement Benefit Obligations	**43.6**	46.3	43.7
Income Taxes	**13.2**	15.1	14.5
Environmental Obligations	**20.6**	21.4	22.7
Deferred Storm Charges	**21.0**	14.1	14.6
Other	**10.1**	8.2	7.9
Total Regulatory Assets	**$ 158.6**	$ 171.1	$ 166.4
Less: Current Portion of Regulatory Assets(1)	**16.6**	20.5	21.9
Regulatory Assets – noncurrent	**$ 142.0**	$ 150.6	$ 144.5

(1) Reflects amounts included in Accrued Revenue on the Company's Consolidated Balance Sheets.

The Company receives a return on investment on its regulated assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution and transmission utilities will recover their investments in long-lived assets, including regulatory assets. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Utility Revenue Recognition – Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts – The Company recognizes a provision for doubtful accounts each month based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. At the end of each month, an analysis of the delinquent receivables is performed which takes into account an assumption about the cash recovery of delinquent receivables. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company's distribution utilities are authorized by regulators to recover the costs of their energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations – The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs.

The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2009 and 2008, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $300,000 and $200,000, respectively, in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2009 and 2008, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $735,000 and $675,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $576,000 and $531,000, respectively. See Note 9 to the accompanying Consolidated Financial Statements.

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets.

Depreciation – Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies – The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of September 30, 2010, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

As of September 30, 2010, the Company and its subsidiaries had 437 employees. The Company considers its relationship with employees to be good and has not experienced any major labor disruptions.

As of September 30, 2010, 150 of the Company's employees were represented by labor unions. These employees are covered by four separate collective bargaining agreements which expire on March 31, 2012, May 31, 2012, May 31, 2013 and June 5, 2014. The agreements provide discreet salary adjustments, established work practices and uniform benefit packages. The Company expects to negotiate new agreements prior to their expiration dates.

INTEREST RATE RISK

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the average amount of short-term debt outstanding was $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rates on the Company's short-term borrowings for the three months ended September 30, 2010 and September 30, 2009 were 2.32% and 2.05%, respectively. The average interest rates on the Company's short-term borrowings for the nine months ended September 30, 2010 and September 30, 2009 were 2.30% and 3.82%, respectively.

MARKET RISK

Although Unitil's three distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Table of Contents

Item 1. *Financial Statements*

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Operating Revenues				
Gas	**$ 17.4**	$ 15.2	**$ 102.2**	$ 111.0
Electric	**57.5**	54.2	**154.9**	163.3
Other	**1.2**	1.0	**3.4**	3.2
Total Operating Revenues	**76.1**	70.4	**260.5**	277.5
Operating Expenses				
Purchased Gas	**8.9**	6.9	**61.5**	67.1
Purchased Electricity	**39.6**	38.9	**107.1**	119.5
Operation and Maintenance	**13.1**	12.0	**36.9**	34.4
Conservation & Load Management	**1.6**	1.2	**5.8**	3.7
Depreciation and Amortization	**6.2**	6.6	**20.4**	19.3
Provisions (Benefit) for Taxes:				
Local Property and Other	**2.7**	2.4	**8.3**	7.6
Federal and State Income	**(0.6)**	(1.0)	**2.3**	4.4
Total Operating Expenses	**71.5**	67.0	**242.3**	256.0
Operating Income	**4.6**	3.4	**18.2**	21.5
Non-Operating Expenses (Income)	**—**	—	**0.3**	0.2
Income Before Interest Expense	**4.6**	3.4	**17.9**	21.3
Interest Expense, Net	**4.7**	4.0	**13.5**	12.5
Net Income (Loss)	**(0.1)**	(0.6)	**4.4**	8.8
Less: Dividends on Preferred Stock	**—**	—	**0.1**	0.1
Earnings (Loss) Applicable to Common Shareholders	**$ (0.1)**	$ (0.6)	**$ 4.3**	$ 8.7
Weighted Average Common Shares Outstanding – Basic (000's)	**10,830**	10,767	**10,817**	9,267
Weighted Average Common Shares Outstanding – Diluted (000's)	**10,830**	10,767	**10,818**	9,267
Earnings Per Common Share (Basic and Diluted)	**$ (0.01)**	$ (0.06)	**$ 0.40**	$ 0.94
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.38**	$ 1.38

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)
(UNAUDITED)

	September 30,		December 31,
	2010	**2009**	**2009**
ASSETS:			
Utility Plant:			
Electric	**$ 313.5**	$ 300.0	$ 302.3
Gas	**348.5**	316.9	325.5
Common	**30.4**	28.8	28.9
Construction Work in Progress	**18.9**	19.6	26.0
Total Utility Plant	**711.3**	665.3	682.7
Less: Accumulated Depreciation	**247.7**	227.4	233.0
Net Utility Plant	**463.6**	437.9	449.7
Current Assets:			
Cash	**8.0**	9.0	7.7
Accounts Receivable – Net of Allowance for Doubtful Accounts of $2.6, $2.4 and $2.5	**27.2**	27.2	33.5
Accrued Revenue	**35.7**	34.0	44.0
Gas Inventory	**15.9**	13.8	14.3
Materials and Supplies	**3.3**	2.9	2.6
Prepayments and Other	**3.0**	8.3	4.7
Total Current Assets	**93.1**	95.2	106.8
Noncurrent Assets:			
Regulatory Assets	**142.0**	150.6	144.5
Other Noncurrent Assets	**26.3**	27.5	24.2
Total Noncurrent Assets	**168.3**	178.1	168.7
TOTAL ASSETS	**$ 725.0**	$ 711.2	$ 725.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)
(UNAUDITED)

	September 30, 2010	September 30, 2009	December 31, 2009
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 183.5**	$ 191.6	$ 193.1
Preferred Stock	**2.0**	2.0	2.0
Long-Term Debt, Less Current Portion	**288.5**	249.0	248.9
Total Capitalization	**474.0**	442.6	444.0
Current Liabilities:			
Long-Term Debt, Current Portion	**0.5**	0.4	0.4
Accounts Payable	**16.0**	18.6	25.1
Short-Term Debt	**46.3**	54.0	64.5
Energy Supply Contract Obligations	**23.0**	21.4	23.1
Other Current Liabilities	**24.2**	25.0	16.6
Total Current Liabilities	**110.0**	119.4	129.7
Deferred Income Taxes	**37.2**	38.2	39.8
Noncurrent Liabilities:			
Energy Supply Contract Obligations	**13.6**	24.3	21.7
Retirement Benefit Obligations	**67.2**	69.2	65.5
Environmental Obligations	**14.2**	10.9	14.3
Other Noncurrent Liabilities	**8.8**	6.6	10.2
Total Noncurrent Liabilities	**103.8**	111.0	111.7
TOTAL CAPITALIZATION AND LIABILITIES	**$ 725.0**	$ 711.2	$ 725.2

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Nine Months Ended September 30, 2010	2009
Operating Activities:		
Net Income	**$ 4.4**	$ 8.8
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**20.4**	19.3
Deferred Tax Provision	**(0.9)**	5.1
Changes in Working Capital Items:		
Accounts Receivable	**6.3**	12.5
Accrued Revenue	**8.3**	22.9
Gas Inventory	**(1.6)**	17.8
Accounts Payable	**(9.1)**	(9.9)
Other Changes in Working Capital Items	**1.2**	(8.2)
Deferred Regulatory and Other Charges	**(4.0)**	(14.3)
Other, net	**(3.5)**	(8.6)
Cash Provided by Operating Activities	**21.5**	45.4
Investing Activities:		
Property, Plant and Equipment Additions	**(33.8)**	(43.0)
Acquisition Costs	**—**	(6.8)
Cash (Used in) Investing Activities	**(33.8)**	(49.8)
Financing Activities:		
Repayment of Short-Term Debt	**(18.2)**	(20.1)
Proceeds From Issuance (Repayment of) Long-Term Debt, net	**39.7**	(0.3)
Net Increase (Decrease) in Gas Inventory Financing	**2.3**	(24.2)
Dividends Paid	**(11.3)**	(9.4)
Proceeds from Issuance of Common Stock, net	**0.7**	56.2
Other, net	**(0.6)**	(0.3)
Cash Provided by Financing Activities	**12.6**	1.9
Net Increase (Decrease) in Cash	**0.3**	(2.5)
Cash at Beginning of Period	**7.7**	11.5
Cash at End of Period	**$ 8.0**	$ 9.0
Supplemental Cash Flow Information:		
Interest Paid	**$ 12.5**	$ 11.6
Income Taxes Paid	**$ 1.0**	$ 0.6

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (Unitil Energy), Fitchburg Gas and Electric Light Company (Fitchburg), Northern Utilities, Inc. (Northern Utilities), Granite State Gas Transmission, Inc. (Granite), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. (collectively, "Usource") are subsidiaries of Unitil Resources.

On December 1, 2008, the Company purchased: (i) all of the outstanding capital stock of Northern Utilities, a natural gas distribution utility serving customers in Maine and New Hampshire, from Bay State Gas Company (Bay State) and (ii) all of the outstanding capital stock of Granite, an interstate gas transmission pipeline company primarily serving the needs of Northern Utilities, from NiSource, Inc. (NiSource) pursuant to the Stock Purchase agreement dated as of February 15, 2008 by and among NiSource, Bay State, and Unitil (the "Acquisitions"). The final purchase price allocation is disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on February 10, 2010.

Unitil's principal business is the local distribution of electricity in the southeastern seacoast and state capital regions of New Hampshire and the greater Fitchburg area of north central Massachusetts and the local distribution of natural gas in southeastern New Hampshire, portions of southern and central Maine and in the greater Fitchburg area of north central Massachusetts. Unitil has three distribution utility subsidiaries, Unitil Energy, which operates in New Hampshire, Fitchburg, which operates in Massachusetts and Northern Utilities, which operates in New Hampshire and Maine (collectively referred to as the distribution utilities).

Granite is a natural gas transportation pipeline, operating 87 miles of underground gas transmission pipeline primarily located in Maine, New Hampshire and Massachusetts. Granite provides Northern Utilities with interconnection to three major natural gas pipelines and access to domestic natural gas supplies in the south and Canadian natural gas supplies in the north. Granite derives its revenues principally from the transportation services provided to Northern Utilities and, to a lesser extent, third –party marketers.

A fifth utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for Unitil Energy. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of Unitil Energy on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve Unitil Energy's customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service; Unitil Realty; and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology, energy management and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource is a wholly-owned subsidiary of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and nine months ended September 30, 2010 are not necessarily indicative of results to be expected for the year ending December 31, 2010. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission (SEC) on February 10, 2010, for a description of the Company's Basis of Presentation.

Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the Acquisitions. As a result of the Acquisitions and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisitions and stock issuance is fully reflected in both reporting periods. Also, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

Derivatives – The Company has a regulatory approved hedging program for Northern Utilities designed to fix a portion of its gas supply costs for the coming year of service. In order to fix these costs, the Company purchases natural gas futures contracts on the New York Mercantile Exchange (NYMEX) that correspond to the associated delivery month. Any gains or losses resulting from the change in the fair value of these derivatives are passed through to ratepayers directly through a regulatory commission approved recovery mechanism. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company records gains and losses resulting from the change in fair value of the derivatives as regulatory liabilities or assets, then reclassifies these gains or losses into Purchased Gas when the gains and losses are passed through to customers in accordance with rate reconciling mechanisms.

As of September 30, 2010, September 30, 2009 and December 31, 2009, the Company had 1.3 billion, 2.1 billion and 1.9 billion cubic feet (BCF), respectively, outstanding in natural gas purchase contracts under its hedging program.

Liability Derivatives ($ millions)

The tables below show derivatives, which are part of the regulatory approved hedging program, that are not designated as hedging instruments, under FASB ASC 815-20. As discussed above, the change in fair value related to these derivatives is recorded initially as a Regulatory Asset then reclassified to Purchased Gas in accordance with the recovery mechanism. The tables below include disclosure of the Regulatory Asset and reclassifications from the Regulatory Asset into Purchased Gas.

Fair Value Amount Offset in Regulatory Assets, as of:

Description	Balance Sheet Location	Fair Value September 30, 2010	Fair Value September 30, 2009	Fair Value December 31, 2009
Natural Gas Futures Contracts	Other Current Liabilities	$ 1.7	$ 3.6	$ 2.2
Natural Gas Futures Contracts	Other Noncurrent Liabilities	0.3	—	0.1
Total		$ 2.0	$ 3.6	$ 2.3

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Amount of (Gain) / Loss Recognized in Regulatory Assets for Derivatives:				
Natural Gas Futures Contracts	$ 0.7	$ (1.9)	$ 3.6	$ 3.7
Amount of Loss Reclassified into Consolidated Statements of Earnings[(1)]:				
Purchased Gas	$ —	$ —	$ 3.9	$ 5.8

(1) These amounts are offset in the Consolidated Statements of Earnings with Accrued Revenue and therefore there is no effect on earnings.

Subsequent Events – The Company has evaluated all events or transactions through the date of this filing. During this period, the Company did not have any material subsequent events that impacted its consolidated financial statements.

Reclassifications – Certain amounts previously reported have been reclassified to improve the financial statements' presentation and to conform to current year presentation.

Recently Issued Pronouncements – There are no recently issued pronouncements that the Company has not already adopted.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
09/22/10	11/15/10	11/01/10	$0.345
06/17/10	08/16/10	08/02/10	$0.345
03/25/10	05/14/10	04/30/10	$0.345
01/14/10	02/16/10	02/02/10	$0.345
09/23/09	11/16/09	11/02/09	$0.345
06/18/09	08/14/09	07/31/09	$0.345
03/26/09	05/15/09	05/01/09	$0.345
01/15/09	02/16/09	02/02/09	$0.345

Table of Contents

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

Common Stock

The Company's common stock trades under the symbol "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the number of authorized shares of the Company's common stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's common stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company had 10,879,741, 10,827,061 and 10,836,759 of common shares outstanding at September 30, 2010, September 30, 2009 and December 31, 2009, respectively.

Unitil Corporation Common Stock Offering – Between December 2008 and June 2009, the Company sold 4,970,000 shares of its common stock at a price of $20.00 per share in registered public offerings. The Company used the net proceeds of $93.1 million from these offerings primarily to complete the acquisitions of Northern Utilities and Granite. Please see Note 3 to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2009 as filed with the SEC on February 10, 2010 for additional information.

Dividend Reinvestment and Stock Purchase Plan – During the first nine months of 2010, the Company sold 30,934 shares of its Common Stock, at an average price of $21.68 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans, resulting in net proceeds of approximately $671,000.

During the first nine months of 2009, the Company sold 33,184 shares of its Common Stock, at an average price of $20.88 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans, resulting in net proceeds of approximately $693,000.

Restricted Stock Plan – The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 5, 2010, 12,520 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $262,920. There were 33,608 and 40,153 non-vested shares under the Plan as of September 30, 2010 and 2009, respectively. The weighted average grant date fair value of these shares was $21.92 and $22.87, respectively. The compensation expense associated with the issuance of shares under the Plan is being recognized over the vesting period and was $0.4 million and $0.4 million for the nine months ended September 30, 2010 and 2009, respectively. At September 30, 2010, there was approximately $0.9 million of total unrecognized compensation cost under the Plan which is expected to be recognized over approximately 2.5 years. There were 472 restricted shares forfeited under the Plan during the nine months ended September 30, 2010. There were no cancellations under the Plan during the nine months ended September 30, 2010.

Table of Contents

Preferred Stock

Details on preferred stock at September 30, 2010, September 30, 2009 and December 31, 2009 are shown below:

(Amounts in Millions)

	September 30,		December 31,
	2010	**2009**	**2009**
Preferred Stock			
Unitil Energy Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
Fitchburg Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.8	0.8
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.0**	$ 2.0	$ 2.0

[Table of Contents](#)

NOTE 4 – LONG-TERM DEBT, CREDIT ARRANGEMENTS AND GUARANTEES

Long-Term Debt

Details on long-term debt at September 30, 2010, September 30, 2009 and December 31, 2009 are shown below ($ Millions):

	September 30,		December 31,
	2010	2009	2009
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
5.24% Series, Due March 2, 2020	**15.0**	—	—
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Northern Utilities Senior Notes:			
6.95% Senior Notes, Due December 3, 2018	**30.0**	30.0	30.0
5.29% Senior Notes, Due March 2, 2020	**25.0**	—	—
7.72% Senior Notes, Due December 3, 2038	**50.0**	50.0	50.0
Granite Senior Notes:			
7.15% Senior Notes, Due December 15, 2018	**10.0**	10.0	10.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due Through August 1, 2017	**4.0**	4.4	4.3
Total Long-Term Debt	**289.0**	249.4	249.3
Less: Current Portion	**0.5**	0.4	0.4
Total Long-term Debt, Less Current Portion	**$ 288.5**	$ 249.0	$ 248.9

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at September 30, 2010 is estimated to be approximately $329 million, before considering any costs, including prepayment costs, which generally require a "make-whole" payment, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

On March 2, 2010, Unitil Energy completed the sale of $15 million of First Mortgage Bonds through a private placement to institutional investors. The First Mortgage Bonds have a maturity of ten years and a coupon rate of 5.24%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

On March 2, 2010, Northern Utilities completed the sale of $25 million of Senior Unsecured Notes through a private placement to institutional investors. The Senior Unsecured Notes have a maturity of ten years and a coupon rate of 5.29%. The Company used the proceeds from this long-term financing to repay short-term debt and for general corporate purposes.

Credit Arrangements

At September 30, 2010, the Company had $46.3 million in short-term debt outstanding through bank borrowings under its revolving credit facility which extends through October 8, 2013. The borrowing limit under the revolving credit facility is $80.0 million. The total amount of credit available under the Company's revolving credit facility at September 30, 2010 was $33.7 million. The revolving credit facility contains customary terms and conditions for credit facilities of this type, including, without limitation, covenants restricting the Company's ability to incur liens, merge or consolidate with another entity or change its line of business. The revolving credit agreement also contains a covenant restricting the Company's ability to permit funded debt to exceed 65% of capitalization at the end of each fiscal quarter. As of September 30, 2010, the Company was in compliance with the financial covenants contained in the revolving credit agreement.

On October 8, 2010, the Company entered into the Fourth Amendment Agreement with Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto (the "Fourth Amendment Agreement"), further amending the credit agreement dated as of November 26, 2008 among Unitil, Bank of America, N.A., as administrative agent, and a syndicate of other lenders party thereto. The credit agreement was previously amended on January 2, 2009, March 16, 2009, and October 13, 2009 to, among other things, increase the maximum borrowings under the facility to $80.0 million. The Fourth Amendment Agreement extends the scheduled termination date of the credit agreement to October 8, 2013 and provides for two conditional one-year extensions subsequent to the October 8, 2013 termination date (if agreed to among the lenders and Unitil). The Fourth Amendment Agreement also provides the Company a mechanism to request an increase in maximum borrowings of $20.0 million (in increments of not less than $5.0 million). The Fourth Amendment Agreement also provides a new letter of credit sub-facility pursuant to which up to $25.0 million of the credit agreement may be used for the purpose of issuing letters of credit for Unitil or its subsidiaries.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $12.3 million, $7.6 million and $10.0 million outstanding at September 30, 2010, September 30, 2009 and December 31, 2009, respectively, related to these asset management agreements.

Guarantees

The Company also provides limited guarantees on certain energy and natural gas storage management contracts entered into by the three distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2010 there are $34.5 million of guarantees outstanding and the longest of these guarantees extends through October 31, 2011. Of this amount, $12.0 million is related to Unitil's guarantee of payment for the term of the Northern Utilities' gas storage agreement discussed above.

The Company also guarantees the payment of principal, interest and other amounts payable on the notes issued by Unitil Realty and Granite. As of September 30, 2010, the principal amount outstanding for the 8% Unitil Realty notes was $4.0 million. On December 15, 2008, the Company entered into a guarantee for the payment of principal, interest and other amounts payable on the $10 million Granite notes due

2018. As of September 30, 2010, the principal amount outstanding for the 7.15% Granite notes was $10.0 million. This guarantee will terminate if Granite reorganizes and merges with and into Northern Utilities.

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and nine months ended September 30, 2010 and September 30, 2009 (Millions):

	Electric	Gas	Other	Non-Regulated	Total
Three Months Ended September 30, 2010					
Revenues	**$ 57.5**	**$ 17.4**	**$ —**	**$ 1.2**	**$ 76.1**
Segment Profit (Loss)	**3.0**	**(3.4)**	**(0.1)**	**0.4**	**(0.1)**
Capital Expenditures	**6.0**	**7.5**	**1.1**	**—**	**14.6**
Three Months Ended September 30, 2009					
Revenues	$ 54.2	$ 15.2	$ —	$ 1.0	$ 70.4
Segment Profit (Loss)	1.9	(2.9)	—	0.4	(0.6)
Capital Expenditures	6.1	10.1	0.7	—	16.9
Nine Months Ended September 30, 2010					
Revenues	**$ 154.9**	**$ 102.2**	**$ —**	**$ 3.4**	**$ 260.5**
Segment Profit (Loss)	**5.0**	**(1.9)**	**0.1**	**1.1**	**4.3**
Capital Expenditures	**13.9**	**17.8**	**2.1**	**—**	**33.8**
Segment Assets	**356.8**	**356.6**	**6.9**	**4.7**	**725.0**
Nine Months Ended September 30, 2009					
Revenues	$ 163.3	$ 111.0	$ —	$ 3.2	$ 277.5
Segment Profit (Loss)	3.2	4.2	0.1	1.2	8.7
Capital Expenditures	21.2	21.0	0.8	—	43.0
Segment Assets	348.5	352.6	8.0	2.1	711.2

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED MORE FULLY IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2009 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 10, 2010.

Legal Proceedings

A putative class action Complaint was filed against Fitchburg on January 7, 2009 in Worcester Superior Court in Worcester, Massachusetts, captioned Bellerman v. Fitchburg Gas and Electric Light Company. On April 1, 2009 an Amended Complaint was filed in Worcester Superior Court and served on Fitchburg. The Amended Complaint seeks an unspecified amount of damages including the cost of temporary housing and alternative fuel sources, emotional and physical pain and suffering and property damages allegedly incurred by customers in connection with the loss of electric service during the ice storm in Fitchburg's service territory in December, 2008. The Amended Complaint includes M.G.L. ch. 93A claims for purported unfair and deceptive trade practices related to the December 2008 Storm. On September 4, 2009, the Superior Court issued its order on the Company's Motion to Dismiss the Complaint, granting it in part and denying it in part. The Company anticipates that the court will decide whether the lawsuit is appropriate for class action treatment in the fall of 2011. The Company continues to believe the suit is without merit, and will defend itself vigorously.

Regulatory Matters

Unitil Energy Rate Case Filing – On April 15, 2010, Unitil Energy filed a proposed base rate increase of $10.1 million, an increase of 6.5 percent above present rates. In addition, Unitil Energy requested adjustments for a Rate Year Step Adjustment, a Large Capital Project Step Adjustment and a long-term rate plan establishing step adjustments associated with the Company's Reliability Enhancement Plan and Vegetation Management Plan. On June 29, 2010, the NHPUC issued an order approving a temporary rate increase for Unitil Energy of $5.2 million (annual) effective July 1, 2010 which is being collected by a uniform per kilowatt-hour (kWh) surcharge of $0.00438 on each of Unitil Energy's current rate schedules. Of the $5.2 million rate increase, $500,000 of the increase is intended to permit Unitil Energy to annually recover expenses incurred during the December 2008 ice storm and another $500,000 of the increase is intended to fund higher planned vegetation management program expenditures. Once permanent rates are approved by the NHPUC, they will be reconciled to the date temporary rates were ordered, July 1, 2010. Final review and approval by the NHPUC of Unitil Energy's permanent base rate increase request is scheduled to be completed by February 2011.

Major Ice Storm – On December 11 and 12, 2008, a severe ice storm (December 2008 Ice Storm) struck the New England region. The Company spent approximately $23.3 million for the repair and replacement of electric distribution systems damaged during the storm, including $8.3 million related to capital construction and $15.0 million, including carrying charges, which has been deferred as a regulatory asset, based on orders issued by the MDPU and NHPUC, discussed below. Also, the Company expensed $3.0 million for professional fees related to the ice storm, in addition to normal anticipated expenditures related to emergency storm preparedness. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

The MDPU conducted an investigation of Fitchburg's preparation for and response to the December 2008 Ice Storm during the first half of 2009. On November 2, 2009, the MDPU issued its order with respect to its investigation, finding that Fitchburg's preparation for, and response to, the December 2008 Ice Storm constituted a failure of the Company to meet its public service obligation to provide safe and reliable service, and ordered several remedial actions. First, the MDPU ordered a comprehensive independent management audit of Fitchburg's management practices. The management audit, which will be performed by Jacobs Consultancy Inc., will begin in the fourth quarter of 2010. Second, the MDPU directed Fitchburg to implement a series of operational and capital improvements which had been identified and recommended through the Company's self-assessment review. All of these operational and capital improvements have either been completed or are currently underway, and remain subject to MDPU review. Finally, the MDPU noted that the costs incurred by Fitchburg for the December 2008 Ice Storm would be subject to review in Fitchburg's next electric rate case, along with Fitchburg's rate of return.

On December 30, 2009, the MDPU approved Fitchburg's petition to defer and record as a regulatory asset costs associated with the repair of its electric distribution system from damage caused by the December 2008 Ice Storm for future recovery in rates. The order of approval made no findings as to whether the subject expenses were reasonable or whether they can be recovered from ratepayers, and confirmed that the MDPU will consider the subsequent ratemaking treatment of the expense as part of Fitchburg's next rate case. As of September 30, 2010, Fitchburg has deferred approximately $13.0 million, including carrying charges, associated with the repair of its electric distribution system for future recovery in rates.

On November 9, 2009, the NHPUC granted Unitil Energy's petition to defer and record as a regulatory asset costs associated with electric distribution system damage from the December 2008 Ice Storm until such time as the Commission issues a final order in Unitil Energy's pending base rate case. The Order clarified that the issues of the appropriate amount of the storm related expenses to be recovered, the timing and manner of recovery, and what, if any, return should be applied to the unrecovered balance are to be reviewed in the rate case. As of September 30, 2010, Unitil Energy has deferred approximately $2.0 million, including carrying charges, associated with the repair of its electric distribution system for future recovery in rates.

On January 8, 2010, the NHPUC opened a docket to consider Unitil Energy's response to the December 2008 Ice Storm, including the timing of its response, its restoration priorities and strategies and the procurement and allocation of its resources in New Hampshire and Massachusetts. On September 24, 2010, the NHPUC issued its final order in this matter and closed its investigation, accepting the NHPUC Staff's Report finding that UES had acted reasonably.

Fitchburg – Electric Operations – On November 25, 2009, Fitchburg submitted to the MDPU its annual (2009) reconciliation of costs and revenues for Transition and Transmission under its restructuring plan (the Annual Reconciliation Filing). The rates were approved effective January 1, 2010, subject to reconciliation pending further investigation by the MDPU. This matter remains pending. A final order approving Fitchburg's 2008 Annual Reconciliation Filing was issued on April 12, 2010.

On November 12, 2009, the Governor of Massachusetts signed House Bill 4329. The bill (i) requires the MDPU to establish regulations for utilities to respond to emergencies, (ii) requires utilities to file with the MDPU annual emergency response plans, (iii) authorizes the MDPU to impose penalties for a utility's failure to comply with the MDPU's regulations, and (iv) allows the chair of the MDPU to issue operational and management directives during an emergency. The bill also authorizes the Massachusetts Attorney General to bring a court action for receivership of a small investor-owned utility where an emergency exists and the utility has materially violated the MDPU's standards for responding to emergencies. On February 2, 2010, the MDPU issued an order adopting regulations concerning the items required by House Bill 4329. Fitchburg has complied with the requirements concerning the filing of its emergency response plans and has met with MDPU Staff to review them. On July 30, 2010, the MDPU approved Fitchburg's electric and gas Emergency Response Plans.

Fitchburg – Gas Operations – On November 2, 2009 the MDPU issued an order finding that Fitchburg engaged in certain price stabilization practices for the 2007 / 2008 and 2008 / 2009 heating seasons without the MDPU's prior approval and that Fitchburg's gas purchasing practices were imprudent. As a result, the MDPU required Fitchburg to refund $4.6 million of natural gas costs, plus an appropriate carrying charge based on the prime lending rate, to its gas customers. The Company recorded a pre-tax charge of $4.9 million in the fourth quarter of 2009 based on the MDPU's order. On November 30, 2009, the MDPU approved Fitchburg's proposal to amortize its refund of natural gas costs to customers over a five-year period. Fitchburg has appealed the gas procurement order to the Massachusetts Supreme Judicial Court. Fitchburg believes that its gas-procurement practices were consistent with those of other Massachusetts natural gas distribution companies and all relevant MDPU rules and orders and Massachusetts law. This appeal remains pending before the Massachusetts Supreme Judicial Court. Immediately after the MDPU opened its investigation of this matter in March 2009, Fitchburg ceased making the gas procurement purchases in question and filed a request with the MDPU for approval of a gas procurement plan for future gas purchases. This matter remains pending before the MDPU.

Fitchburg – Other – On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for Revenue Decoupling to be adopted by gas and electric distribution utilities on a going-forward basis, through company-specific rate cases. Revenue decoupling is generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales, and is intended to remove the disincentive a utility has to promote efforts to reduce energy consumption by its customers or to facilitate installation of distributed generation to displace electricity delivered by the utility. It is anticipated that, with limited exceptions, all distribution companies will be operating under decoupling plans by year-end 2012.

On February 11, 2009, the Massachusetts Supreme Judicial Court (SJC) issued its decision in the Attorney General's (AG) appeal of the MDPU orders relating to Fitchburg's recovery of bad debt expense. The SJC agreed with the AG that the MDPU was required to hold hearings regarding changes in Fitchburg's tariff and rates, and on that basis vacated the MDPU orders. The Court, however, declined to rule on an appropriate remedy, and remanded the cases back to the MDPU for consideration of that issue. This matter remains pending before the MDPU.

On July 2, 2008, the Governor of Massachusetts signed into law "The Green Communities Act" (the GC Act), an energy policy statute designed to substantially increase energy efficiency and the development of renewable energy resources in Massachusetts. The GC Act provides for utilities to recover in rates the incremental costs associated with its various mandated programs. Several regulatory proceedings have been initiated to implement various provisions of the GC Act, including provisions for each distribution company to file enhanced three year energy efficiency investment plans, plans to establish smart grid pilot programs, proposals to purchase long-term contracts for renewable energy, special tariffs to allow the net metering of customer-owned renewable generation, and terms and conditions for purchasing supplier receivables. Three year energy efficiency investment plans, plans to establish smart grid pilot programs, and net metering tariffs have been approved by the MDPU. Proposals to purchase long-term contracts for renewable energy and terms and conditions for purchasing supplier receivables are under review in a separately designated docket.

On March 1, 2010, Fitchburg submitted its annual filing to the MDPU of the 2009 Service Quality Reports for its gas division. On October 20, 2010, the MDPU issued its Order on the 2009 Service Quality Reports of the Massachusetts local gas distribution utilities and noted that Fitchburg met or exceeded its established benchmarks in all Service Quality penalty measures. Fitchburg's Service Quality performance was consistent with the MDPU's Service Quality Guidelines and Fitchburg's respective Service Quality plan.

Unitil Energy – Other – In July 2008, the State of New Hampshire enacted legislation that allows electric utilities to make investments in distributed energy resources, including energy efficiency and demand reduction technologies, as well as clean cogeneration and renewable generation. On August 5, 2009 Unitil Energy filed a plan for approval of investment in and rate recovery for Distributed Energy Resources. An order approving a settlement agreement for a time-of-use pilot program was issued on February 26, 2010. On June 11, 2010, the NHPUC issued an order on the remaining two proposed projects and cost recovery. The NHPUC denied one of the two projects, citing that the costs outweighed the benefits but found the other project to be in the public interest. Unitil Energy plans to file adjustments to base distribution rates to collect actual costs associated with authorized DER projects.

On February 25, 2010, a significant wind storm struck portions of the New England region, causing extensive damage to electric facilities and loss of service to significant numbers of customers of several utilities. An estimated one million electric customers in the region were affected, including approximately 85% of the Company's customers. Unitil Energy was able to restore power to 96% percent of its customers by day three, and its final customers, including those with individual service problems, were restored by day four. The Company spent approximately $7.3 million for the repair and replacement of electric distribution systems damaged during the storm, including $1.3 million related to capital construction and $6.0 million which has been deferred as a regulatory asset. Unitil Energy, in its base rate case filing discussed above, has requested recovery in rates for the costs associated with the emergency repair of its electric distribution system for damage caused by this storm. The amount and timing of the cost recovery of the storm restoration expenditures will be determined in the base rate case proceeding. The Company does not believe these storm restoration expenditures and the timing of cost recovery will have a material adverse impact on the Company's financial condition or results of operations. However, if it were ultimately determined that certain of these costs were not recoverable in rates, and/or the Company were required to incur additional costs to defend itself, there may be a significant impact on the Company's results of operations in future periods.

On June 17, 2010, Unitil Energy made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective August 1, 2010, including reconciliation of prior year costs and revenues. On July 30, 2010, the NHPUC approved the rate filing and reconciliation.

Northern Utilities – On November 21, 2008, the MPUC issued an order approving a settlement agreement resolving a number of Notices of Probable Violation ("NOPVs") of certain safety related procedures and rules by Northern Utilities. Under the Settlement, Northern Utilities will incur total expenditures of approximately $3.8 million for safety related improvements to Northern's distribution system to ensure compliance with the relevant state and federal gas safety laws, for which no rate recovery will be allowed. These compliance costs were accrued by Northern Utilities prior to the acquisition date and the remaining amount on the Company's balance sheet at September 30, 2010 was $0.7 million.

On June 27, 2008 the MPUC opened an investigation of Northern Utilities' cast iron pipe replacement activities and the benefits of an accelerated replacement program for cast iron distribution pipe remaining in portions of Northern Utilities' Maine service areas. An Agreement resolving this matter, filed on behalf of Northern Utilities, the Maine Office of the Public Advocate, and several state legislator intervenors, was filed with the MPUC on July 6, 2010. Under the Agreement, Northern Utilities will proceed with a comprehensive upgrade and replacement program (the "Program"), which will provide for the systematic replacement of cast iron, wrought iron and bare steel pipe in Northern Utilities' natural gas distribution system in Portland and Westbrook, Maine and the conversion of the system to intermediate pressure. The Agreement establishes the objective of completing the Program by the end of the 2024 construction season. Under the Agreement, the parties agreed to support a cost recovery mechanism that will provide for the timely recovery of prudently-incurred costs of the Program. The features of this cost recovery mechanism will be finalized during Northern Utilities' next base rate case proceeding, which is anticipated to be filed in early 2011. On July 30, 2010, the MPUC issued its Final Order approving the Settlement Agreement.

Granite State Gas Transmission, Inc. – Base Rate Case Filing – On June 29, 2010, Granite filed a base transportation rate increase which would provide for an initial increase of approximately $2.3 million in annual revenue with the FERC. This represents Granite's first filing for a rate change since its last general rate case in 1997. The effect of this initial rate increase would result in an approximate increase of two percent in the total annual bill to an average residential natural gas heating customer served by Northern Utilities. In addition to its request for new base transportation rates, Granite is seeking FERC approval to implement a capital cost surcharge that would allow Granite to implement a rate surcharge annually to recover certain projected capital expenditures in future periods. On July 30, 2010, the FERC ordered the rate increase to be effective on January 1, 2011, subject to refund and hearing and settlement procedures that are in progress.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED MORE FULLY IN NOTE 7 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2009 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 10, 2010.

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company believes it is in compliance with applicable environmental and safety laws and regulations, and the Company believes that as of September 30, 2010, there were no material losses reasonably likely to be incurred in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included in Environmental Obligations on the Company's Consolidated Balance Sheet at September 30, 2010 are accrued liabilities totaling $12.0 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties. Also included in Environmental Obligations on the Company's Consolidated Balance Sheet at September 30, 2010 are accrued liabilities totaling $2.3 million associated with Northern Utilities' environmental remediation obligations for former MGP sites. In addition to the amounts noted above, there are $0.2 million of accrued liabilities in Other Current Liabilities on the Company's Consolidated Balance Sheet at September 30, 2010 associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the future recovery of these environmental remediation costs is expected based on regulatory precedent and established practices.

NOTE 8: INCOME TAXES

The Company bills its customers sales tax in Massachusetts and Maine and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2009 and for the current interim reporting period ended September 30, 2010 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by the FASB Codification is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no material interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

During the third quarter of 2010, the Company changed its method of tax accounting for certain construction-related costs previously capitalized as depreciable assets, to accounting for those expenditures as repairs expense deductions under Sections 162 and 263(a) of the Internal Revenue Code. In applying the new tax accounting method, certain costs which were previously capitalized and recognized as depreciation deductions over various useful lives for tax accounting purposes are now to be deducted in the year incurred. The Company applied the change retroactively for additional deductions of $20.4 million related to the tax accounting method change in its 2009 federal and state returns.

The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2006; December 31, 2007; and December 31, 2008. Income tax filings for the year ended December 31, 2009 were filed with the Internal Revenue Service (IRS) in September 2010. In its Federal Income Tax return filings for the year ended December 31, 2008, the Company recognized net operating loss (NOL) carrybacks against its Federal Income Tax returns for the years ended December 31, 2006 and 2007 in the amounts of $5.0 million and $6.7 million, respectively. These NOL carrybacks resulted in a refund to the Company of $4.0 million which was received in November 2009. According to Internal Revenue Code rules, NOL refunds in excess of $2.0 million fall under the jurisdiction of the Joint Committee of Congress (Joint Committee) and are subject to review by the IRS and attorneys of the Joint Committee. As a result, on December 30, 2009, the Company received notice that its Federal Income Tax return filings for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 are under examination by the IRS. The IRS is currently performing fieldwork as part of their audit procedures. Currently, the Company believes that the ultimate resolution of this examination will not result in a material adverse effect to the Company's financial position or results of operations.

NOTE 9: RETIREMENT BENEFIT OBLIGATIONS

The Company co-sponsors the Unitil Corporation Retirement Plan (Pension Plan), the Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan), and the Unitil Corporation Supplemental Executive Retirement Plan (SERP) to provide certain pension and postretirement benefits for its retirees and current employees. Please see Note 9 to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2009 as filed with the SEC on February 10, 2010 for additional information regarding these plans.

Table of Contents

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

	2010	2009
Used to Determine Plan Costs		
Discount Rate	**5.75%**	6.25%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**7.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2017

The following tables provide the components of the Company's Retirement plan costs ($000's):

	Pension Plan		PBOP Plan		SERP	
Three Months Ended September 30,	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Service Cost	**$ 653**	$ 571	**$ 366**	$ 357	**$ 71**	$ 54
Interest Cost	**1,114**	1,073	**504**	578	**56**	46
Expected Return on Plan Assets	**(1,045)**	(1,108)	**(150)**	(89)	**—**	—
Prior Service Cost Amortization	**63**	66	**395**	428	**—**	—
Transition Obligation Amortization	**—**	—	**5**	5	**—**	—
Actuarial Loss Amortization	**601**	399	**—**	—	**34**	17
Sub-total	**1,386**	1,001	**1,120**	1,279	**161**	117
Amounts Capitalized and Deferred	**(522)**	(388)	**(231)**	(486)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 864**	$ 613	**$ 889**	$ 793	**$ 161**	$ 117

	Pension Plan		PBOP Plan		SERP	
Nine Months Ended September 30,	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Service Cost	**$ 1,957**	$ 1,713	**$ 1,099**	$ 1,071	**$ 213**	$ 162
Interest Cost	**3,343**	3,220	**1,512**	1,735	**170**	136
Expected Return on Plan Assets	**(3,136)**	(3,324)	**(449)**	(267)	**—**	—
Prior Service Cost Amortization	**190**	198	**1,184**	1,284	**2**	(1)
Transition Obligation Amortization	**—**	—	**16**	15	**—**	—
Actuarial Loss Amortization	**1,804**	1,197	**—**	—	**100**	53
Sub-total	**4,158**	3,004	**3,362**	3,838	**485**	350
Amounts Capitalized and Deferred	**(1,625)**	(1,034)	**(818)**	(1,286)	**—**	—
Net Periodic Benefit Cost Recognized	**$ 2,533**	$ 1,970	**$ 2,544**	$ 2,552	**$ 485**	$ 350

Employer Contributions

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA were new minimum funding rules which went into effect for plan years beginning in 2008. The funding target was 100% of a plan's liability (as determined under the PPA) with any shortfall amortized over seven years, with lower (92%—100%) funding targets available to well-funded plans during the transition period. Due to the significant declines in the valuation of capital markets during 2008, the Worker, Retiree, and Employer Recovery Act of 2008 (Recovery Act) was signed into law on December 23, 2008. Included in the Recovery Act are temporary modifications to the minimum funding rules set forth in the PPA such that all plans, except those that were subject to deficit reduction contribution requirements in 2007, are allowed to amortize any shortfall from the lower funding targets, rather than the 100% target, for the 2008—2010 plan years. This did not affect the Company's Pension Plan in 2009 as its Pension Plan was 94% funded under the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) as of January 1, 2008 and met the exemption from the shortfall amortization. As of September 30, 2010, the Company had made $3.7 million of contributions to the Pension Plan in 2010. The Company presently anticipates contributing an additional $0.6 million to fund its Pension Plan in 2010.

As of September 30, 2010, the Company had made $2.6 million and $40,000 of contributions to the PBOP and SERP Plans, respectively, in 2010. The Company presently anticipates contributing an additional $0.9 million and $13,000 to the PBOP and SERP Plans, respectively, in 2010.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

Management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of September 30, 2010. Based upon this evaluation, the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded as of September 30, 2010 that the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) are effective.

There have been no changes in the Company's internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f) during the fiscal quarter covered by this Form 10-Q that have affected, or are reasonably likely to affect, the Company's internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2009 as filed with the SEC on February 10, 2010.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended September 30, 2010.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the Exchange Act), adopted by the Company on March 25, 2010, the Company will periodically repurchase shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. There is no pool or maximum number of shares related to these purchases; however, the trading plan will automatically terminate when $80,700 in value of shares have been purchased, or, if sooner, on March 25, 2011.

The Company may suspend or terminate this trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws.

The Company's repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
7/1/10 – 7/31/10	—	—	—
8/1/10 – 8/31/10	—	—	—
9/1/10 – 9/30/10	218	$ 21.50	218
Total	218	$ 21.50	218

Item 5. Other Information

On October 25, 2010, the Company issued a press release announcing its results of operations for the three- and nine-month periods ended September 30, 2010. The press release is furnished with this Quarterly Report on Form 10-Q as Exhibit 99.1.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Weighted Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated October 25, 2010 Announcing Earnings For the Quarter Ended September 30, 2010.	Filed herewith

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	UNITIL CORPORATION
	(Registrant)
Date: October 26, 2010	/s/ Mark H. Collin
	Mark H. Collin Chief Financial Officer
Date: October 26, 2010	/s/ Laurence M. Brock
	Laurence M. Brock Chief Accounting Officer

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Weighted Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated October 25, 2010 Announcing Earnings For the Quarter Ended September 30, 2010.	Filed herewith

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER WEIGHTED AVERAGE COMMON SHARE OUTSTANDING

(Millions except common shares and per share data)

(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net Income (Loss)	**$ (0.1)**	**$ (0.6)**	**$ 4.4**	$ 8.8
Less: Dividend Requirements on Preferred Stock	**—**	**—**	**0.1**	0.1
Net Income Applicable to Common Stock	**$ (0.1)**	**$ (0.6)**	**$ 4.3**	$ 8.7
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**10,830**	**10,767**	**10,817**	9,267
Dilutive Effect of Stock Options and Restricted Stock (000's)	**—**	**—**	**1**	—
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**10,830**	**10,767**	**10,818**	9,267
Earnings Per Share – Basic and Diluted	**$ (0.01)**	**$ (0.06)**	**$ 0.40**	$ 0.94

Weighted average options to purchase 33,000 and 66,500 shares of common stock were outstanding during the three month periods ended September 30, 2010 and September 30, 2009, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Also, 5,460 and 12,250 weighted average non-vested restricted shares for the three month periods ended September 30, 2010 and September 30, 2009, respectively were not included in the above computation because the effect would have been antidilutive. Additionally, 28,148 and 23,888 weighted average non-vested restricted shares for the three month periods ended September 30, 2010 and September 30, 2009, respectively were not included in the above computation because the Company was in a net loss position for those periods.

Weighted average options to purchase 33,000 and 66,500 shares of common stock were outstanding during the nine month periods ended September 30, 2010 and September 30, 2009, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive. Additionally, 6,867 and 35,302 weighted average non-vested restricted shares for the nine month periods ended September 30, 2010 and September 30, 2009, respectively were not included in the above computation because the effect would have been antidilutive.

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2010
/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2010
/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2010
/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending September 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	October 26, 2010
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	October 26, 2010
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	October 26, 2010

Exhibit 99.1

Contact: David Chong – Investor Relations
Phone: 603-773-6499
Email: chong@unitil.com
Alec O'Meara – Media Relations
Phone: 603-773-6404
Email: omeara@unitil.com

Unitil Reports Third Quarter Results

Hampton, NH – October 25, 2010: Unitil Corporation ("Company") (NYSE: UTL) (www.unitil.com) today announced a net loss of ($0.1) million for the third quarter of 2010, an improvement of $0.5 million compared to the third quarter of 2009. For the nine months ended September 30, 2010, the Company reported net income of $4.3 million compared to $8.7 million for the same period of 2009. Results for the third quarter were driven primarily by higher electric sales margins reflecting favorable summer weather and higher rates, partially offset by increases in operating and interest costs.

Earnings (loss) per common share (EPS) were ($0.01) and $0.40 for the three and nine month periods ended September 30, 2010 compared with ($0.06) and $0.94 for the same periods of 2009. The Company's EPS for 2010 are not directly comparable with 2009 due to the issuance of 5.0 million common shares between December 2008 and June 2009 to complete the financing of the Company's acquisition of Northern Utilities Inc. (Northern Utilities) and Granite State Gas Transmission, Inc. (Granite), the ("Acquisition").

"We continue to make good progress on our regulatory agenda with a target of completing a reset of rates in each of our regulatory jurisdictions within the next twelve months," said Bob Schoenberger, Unitil's Chairman and Chief Executive Officer. "We are also pleased to see a rebound in electric sales and margin in the quarter due to favorable summer weather and an uptick in overall economic activity."

Natural gas sales margin was unchanged in the third quarter of 2010 compared to the same period in 2009. For the nine month period ended September 30, 2010, gas sales margin was $3.8 million lower compared to the same period in 2009. Total natural gas therm sales were 2.7% and 5.5% lower in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. Lower gas therm sales in the Company's utility service territories reflect the effect of milder winter temperatures earlier in 2010, where there were approximately 13% fewer Heating Degree Days in the nine month period, compared to the prior year.

Electric sales margin increased $2.4 million and $2.5 million in the three and nine months ended September 30, 2010 compared to the same periods in 2009, reflecting higher electric kilowatt-hour (kWh) sales and an electric rate increase implemented in July 2010 for the Company's New Hampshire electric distribution utility. Total kWh sales increased 11.1% and 4.9% in the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009 reflecting increased sales to all customer groups. The increased sales reflect above average summer temperatures in the Company's utility service territories in 2010. According to ISO-New England, the grid operator for the New England region, July was the second-hottest July in New England since 1960 and New England's all-time electricity consumption for one month was recorded in that month.

The Company filed two base rate cases in the second quarter of 2010, one for its New Hampshire electric distribution utility, Unitil Energy Systems, Inc. (Unitil Energy) and one for its interstate natural gas transmission pipeline subsidiary, Granite. The New Hampshire Public Utilities Commission (NHPUC) has approved a temporary rate increase of $5.2 million on an annual basis, including recovery of 2008 ice storm costs, for Unitil Energy effective July 1, 2010. The Company expects the NHPUC to issue its final decision in this rate proceeding in the first quarter of 2011. On June 29, 2010 Granite filed a rate proposal with the Federal Energy Regulatory

Commission for an initial annual increase in revenues of approximately $2.3 million. Granite's initial proposed rate increase is effective January 1, 2011, subject to refund and the outcome of hearing and settlement procedures that are in progress. Additionally, the Company's two other distribution utilities, Fitchburg Gas and Electric Light Company and Northern Utilities, are currently preparing base rate cases and anticipate completing them with their respective state regulatory commissions within the next twelve months.

Selected Financial Data for 2010 and 2009 is presented in the following table:

Unitil Corporation – Condensed Consolidated Financial Data

(Millions, except Per Share data)(Unaudited)

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2010	**2009**	**Change**	**2010**	**2009**	**Change**
Gas Therm Sales:						
Residential	2.5	2.9	(13.8%)	26.9	29.1	(7.6%)
Commercial/Industrial	19.3	19.5	(1.0%)	100.9	106.1	(4.9%)
Total Gas Therm Sales	**21.8**	**22.4**	**(2.7%)**	**127.8**	**135.2**	**(5.5%)**
Electric kWh Sales:						
Residential	198.7	172.1	15.5%	524.7	493.8	6.3%
Commercial/Industrial	284.6	263.0	8.2%	767.9	738.3	4.0%
Total Electric kWh Sales	**483.3**	**435.1**	**11.1%**	**1,292.6**	**1,232.1**	**4.9%**
Gas Revenues	$ 17.4	$ 15.2	$ 2.2	$ 102.2	$ 111.0	$ (8.8)
Purchased Gas	9.5	7.3	2.2	63.7	68.7	(5.0)
Gas Sales Margin	**7.9**	**7.9**	**—**	**38.5**	**42.3**	**(3.8)**
Electric Revenues	57.5	54.2	3.3	154.9	163.3	(8.4)
Purchased Electricity	40.6	39.7	0.9	110.7	121.6	(10.9)
Electric Sales Margin	**16.9**	**14.5**	**2.4**	**44.2**	**41.7**	**2.5**
Usource Sales Margin	**1.2**	**1.0**	**0.2**	**3.4**	**3.2**	**0.2**
Total Sales Margin:	**26.0**	**23.4**	**2.6**	**86.1**	**87.2**	**(1.1)**
Operation & Maintenance Expenses	13.1	12.0	1.1	36.9	34.4	2.5
Depreciation, Amortization, Taxes & Other	8.3	8.0	0.3	31.4	31.6	(0.2)
Interest Expense, Net	4.7	4.0	0.7	13.5	12.5	1.0
Earnings (Loss) Applicable to Common Shareholders:	**$ (0.1)**	**$ (0.6)**	**$ 0.5**	**$ 4.3**	**$ 8.7**	**$ (4.4)**
Earnings (Loss) Per Share	**$ (0.01)**	**$ (0.06)**	**$ 0.05**	**$ 0.40**	**$ 0.94**	**$ (0.54)**

Operation and Maintenance (O&M) expenses increased $1.1 million and $2.5 million for the three and nine months ended September 30, 2010, respectively, compared to 2009. The changes in O&M expenses reflect higher utility operating costs and professional fees. O&M expenses reflect the full integration of Northern Utilities and Granite into the Company's consolidated operating results.

Depreciation and Amortization expense decreased $0.4 million and increased $1.1 million in the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009, reflecting higher depreciation on normal utility plant additions partially offset by lower amortization expense in the current year.

Interest Expense, Net increased $0.7 million and $1.0 million in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009. In March 2010, Unitil Energy and Northern Utilities collectively issued $40 million of long-term debt which is contributing to the higher interest expense in the three and nine month periods.

Federal and State Income Taxes decreased by $2.1 million for the nine month period due to lower pre-tax income in 2010 compared to 2009.

All other expenses increased $0.3 million and $0.8 million in the three and nine month periods ended September 30, 2010, respectively, compared to the same periods in 2009, primarily reflecting higher property and payroll taxes.

In the third quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

EPS for the nine months ended September 30, 2010 reflect a higher number of average shares outstanding year over year. Between December 2008 and June 2009 the Company issued 5.0 million common shares to complete the Acquisition. As a result of the Acquisition and the issuance of new common shares, consolidated results for the Company in the current period may not be directly comparable to prior period results until such time as the Acquisition and stock issuance is fully reflected in both reporting periods. Additionally, the Company's results are expected to reflect the seasonal nature of the acquired natural gas businesses. Accordingly, the Company expects that results of operations will be positively affected during the first and fourth quarters, when sales of natural gas are typically higher, and negatively affected during the second and third quarters, when gas operating and maintenance expenses usually exceed sales margins in the period.

The Company will hold a quarterly conference call to discuss third quarter 2010 results on Monday, October 25, 2010 at 5:30 p.m. Eastern Time. This call is being webcast by Thomson Financial and can be accessed in the Investor Relations section of Unitil Corporation's website, www.unitil.com.

About Unitil

Unitil provides for the necessities of life, safely and reliably delivering natural gas and electricity throughout northern New England. We are committed to the communities we serve and to developing people, business practices, and technologies that lead to dependable, more efficient energy. Unitil is a public utility holding company with affiliates that include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc., and Granite State Gas Transmission, Inc. Together, Unitil's operating utilities serve approximately 100,500 electric customers and 70,000 natural gas customers. Other subsidiaries include Unitil Service Corp. and Usource, Unitil's non-regulated business segment. For more information about our people, technologies, and community involvement please visit www.unitil.com.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.11) Detailed list of all membership fees, dues, donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount.

Response:

See Response 26.11

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.12) A list of any management audit and depreciation studies performed within the last 5 years, specifying whether same are on file with the commission;

Response:

Not applicable for Unitil Corporation.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.13) Copies of any audits or studies referred to in (25.12) above which the utility has not submitted to the commission;

Response:

Not applicable for Unitil Corporation.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.14) List of officers and directors of the utility and their compensation for the last 2 years.

Response:
Unitil Corporation was incorporated under the laws of the State of New Hampshire in 1984. Unitil Corporation is a public utility holding company, and is the parent company of Northern Utilities, Inc. ("Northern"). The list below identifies the members of the Board of Directors of Unitil Corporation and their total annual compensation for service on the Unitil Corporation Board of Directors for the past two years:

	2009 [1]		**2010** [1]	
	Compensation	**Common Stock**	**Compensation**	**Common Stock**
William D. Adams	14,600	5,479	18,500	5,492
Robert V. Antonucci	22,600	5,479	23,500	5,492
David P. Brownell	28,600	5,479	29,700	5,492
Michael J. Dalton	25,600	5,479	22,700	5,492
Albert H. Elfner, III	38,600	5,479	36,200	5,492
Edward F. Godfrey	30,100	5,479	39,200	5,492
Michael B. Green	22,600	5,479	24,700	5,492
Eben S. Moulton	36,600	5,479	36,200	5,492
M. Brian O'Shaughnessy	28,600	5,479	26,300	5,492
Robert G. Schoenberger [2]	N/A	N/A	N/A	N/A
Charles H. Tenney III [3]	7,000	--	--	--
Sarah P. Voll	22,600	5,479	21,700	5,492

(1) Includes compensation for service on the Board of Directors for Unitil Corporation and its four utility subsidiaries, Unitil Energy Systems, Inc. ("UES"), Fitchburg Gas and Electric Light Company ("FG&E"), Northern, and Granite State Gas Transmission, Inc. ("GSG"). Unitil Corporation Board of Directors compensation for Unitil Corporation Board meetings is allocated to Unitil Corporation's subsidiaries through the Unitil Service Corp. billing system.
(2) Employee Directors are not compensated for Board service.
(3) Charles H. Tenney III passed away on March 12, 2009.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

The following table lists the total annual compensation for the officers of Unitil Corporation for the past two years. All officers' compensation is allocated to Unitil Corporation's subsidiaries through the Unitil Service Corp. billing system.

	2009			2010		
	Base Salary	**Incentive Pay**	**Restricted Stock**	**Base Salary**	**Incentive Pay**	**Restricted Stock**
Robert G. Schoenberger, Chairman of the Board, Chief Executive Officer & President	456,601	294,796	122,366	456,601	196,338	168,849
Thomas P. Meissner, Jr., Senior Vice President & Chief Operating Officer	224,564	101,000	41,445	224,564	67,594	54,743
Mark H. Collin, Sr. Vice President, Chief Financial Officer & Treasurer	221,942	99,820	37,505	221,942	66,805	54,743
Laurence M. Brock, Chief Accounting Officer & Controller	160,165	41,363	39,512	160,165	38,548	8,280
Sandra L. Whitney, Secretary	81,250	5,187	--	81,250	3,494	1,618

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.15) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;

b. Owned by the spouse or minor child of an officer or director; or

c. Controlled by the officer or director directly or indirectly;

Response:

For Unitil Corporation, the voting stock of the Company consists of common stock only. As of December 31, 2010, common stock outstanding consisted of 10,890,262 shares.

a. There are 150,565 shares owned by officers and/or directors individually.
b. There are 7,838 shares owned by the spouse or minor child of officers and/ or directors.
c. There are 197,559 shares controlled by officers and/or directors, either directly or indirectly, including fully vested but unexercised stock options.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.16) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $50,000 in annual revenues, a list of all payments in excess of $10,000; and

b. For utilities with annual revenues in excess of $50,000, a list of all payments in excess of $50,000.

Response:

See Response 26.16

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.17) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations.

Response:

See Response 26.17

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.18) Balance sheets and income statements for the previous 3 years.

Response:

See Responses 25.10 and 25.02

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.19) Quarterly income statements for the previous 5 years.

Response:

Please see Response 25.10 for quarterly income statements for the previous 2 years (i.e. for 2009 – 2010). Please see the attached for the quarterly income statements for 2006 – 2008. For the periods ending December 31st, quarterly statements are not available. December quarterly amounts for the periods ended December 31st can be derived by subtracting the September YTD amounts from the YTD amounts in the December income statements included in the annual reports included in Response 25.02.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended March 31, 2006

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X__

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 27, 2006
Common Stock, No par value	5,620,672 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended March 31, 2006

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

SAFE HARBOR CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company’s future operations, are forward-looking statements.

These statements include declarations regarding Management’s beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “should,” “expects,” “plans,” “anticipates,” “believes,” “estimates,” “predicts,” “potential” or “continue” or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

? Variations in weather;
? Changes in the regulatory environment;
? Customers’ preferences on energy sources;
? Interest rate fluctuation and credit market concerns;
? General economic conditions;
? Increased competition; and
? Fluctuations in supply, demand, transmission capacity and prices for energy commodities.

Many of these risks are beyond the Company’s control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

Earnings Overview

One of the warmest winters on record in the United States adversely affected the Company’s sales of electricity and natural gas in the first quarter of 2006. The National Oceanic and Atmospheric Administration reported that the United States experienced the warmest January on record in 2006. On average, heating degree days were 12% below the first quarter of 2005 in the Company’s utility service territories.

The Company’s Earnings Applicable to Common Shareholders (Net Income) was $2.0 million for the first quarter of 2006, a decrease of $0.7 million compared to the same period in 2005. Earnings per common share were $0.36 for the first quarter of 2006, a decrease of $0.12 per share compared with earnings of $0.48 per share for the first quarter of 2005. Earnings for the first quarter of 2006 reflect lower unit sales of electricity and natural gas in 2006 compared to the first quarter of 2005 largely due to a milder winter heating season in 2006. Unitil also recorded higher operating costs in the first quarter of 2006 compared to the same period a year earlier.

Total electric kWh sales decreased 1.2% in the three months ended March 31, 2006 compared to the same period in 2005 primarily due to the milder winter heating season in 2006. The weather in the Company's service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005.

Gross electric sales margin decreased $0.9 million in the three month period ended March 31, 2006 compared to the same period in 2005. The decrease in electric margin is due to lower sales volume ($0.2 million) and electric service rate changes ($0.7 million) in the current period compared to the same three month period a year earlier. In particular, in the fourth quarter of 2005, a rate surcharge on Regulatory Assets, the Seabrook Amortization Surcharge (SAS), expired. As a result, the revenues from the SAS are no longer included in electric sales margin. The decrease in revenues resulting from expiration of the SAS is offset by a corresponding decrease in amortization expense related to this Regulatory Asset. The SAS was being collected from customers of the Company's Massachusetts utility operating subsidiary, Fitchburg Gas and Electric Light Company (FG&E) to recover the FG&E's former investment in Seabrook Station, which became fully amortized in 2005.

The Company's New Hampshire utility operating subsidiary, Unitil Energy Systems, Inc. (UES) filed a request for a base rate increase of $4.65 million with the New Hampshire Public Utilities Commission (NHPUC) which established temporary rate relief at current rate levels, effective January 1, 2006. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with a NHPUC order anticipated before the end of 2006. The Company has evaluated the gain contingency criteria under Financial Accounting Standards Board (FASB) Statement No. 5, "Accounting for Contingencies" (SFAS No. 5) and will continue to recognize UES' utility revenues at current rates until such time as the outcome of the rate case can be more clearly determined.

The milder weather caused unit sales of natural gas to residential customers to decline 11.7% in the three months ended March 31, 2006 compared to the same period in 2005. Gas sales to commercial and industrial (C&I) customers were up 8.0% in the three months ended March 31, 2006 compared to the same period in 2005, primarily due to a new special contract with a large industrial customer. Absent the sales associated with this special contract, sales to C&I customers were down 13.8%, reflecting the milder weather.

Gross gas sales margin decreased $0.8 million in the three month period ended March 31, 2006 compared to the same period in 2005. The decrease in gas sales margin is attributable to the lower gas sales volume, as discussed above. A portion of the margin earned by the Company under the new special contract discussed above is deferred for recognition pending the final review of the contract by the Massachusetts Department of Telecommunications and Energy (MDTE) and so the favorable impact on gas firm therm sales due to this contract is not matched by a similar increase in gross gas sales margin.

Total Operation & Maintenance expense increased $0.2 million, or 2.9%, in the three month period ended March 31, 2006 compared to the same period in 2005. The increase reflects higher salaries and compensation costs of $0.2 million, higher retiree and employee benefit costs of $0.1 million, partially offset by lower audit and legal fees of $0.1 million.

Depreciation and Amortization expense decreased $0.9 million for the three month period ended March 31, 2006 compared to the same period in 2005. This decrease was primarily due to lower amortization on regulatory assets. As discussed above, the Company's regulatory assets related to its former abandoned property investment in Seabrook Station became fully-amortized in the fourth quarter of 2005.

Interest Expense, net increased by $0.2 million in the three month period ended March 31, 2006 as compared to the same period in 2005. The change in Interest Expense, net was primarily driven by a higher weighted average cost of debt in the first quarter of 2006 compared to the same period in 2005.

Operating Revenues — Electric

Electric Operating Revenues - Total Electric Operating Revenues, increased by $9.6 million, or 20.5%, in the three month period ended March 31, 2006 compared to the same period in 2005. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating

Revenues reflects higher Purchased Electricity costs $10.6 million, offset by lower sales margin of $0.9 million and lower C&LM revenues of $0.1 million.

As discussed above, the Company has evaluated the gain contingency criteria under SFAS No. 5 regarding the base rate case currently in process with the NHPUC and will continue to recognize UES' utility revenues at current rates until such time as the outcome of the rate case can be more clearly determined.

Purchased Electricity and C&LM revenues increased a net $10.5 million, or 22.4% of Total Electric Operating Revenues in the three month period ended March 31, 2006 compared to the same period in 2005, reflecting higher electric commodity prices and decreased spending on energy efficiency programs that were implemented during those periods. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Gross electric sales margin (Total Electric Operating Revenues less cost of electric sales) was $12.8 million in the three month period ended March 31, 2006. This represents a decrease of $0.9 million, or 1.9% of Total Electric Operating revenues in the three month period compared to the same period in 2005. The lower sales margin reflects $0.2 million related to lower sales volume and $0.7 million related to lower SAS and other utility service revenues. This decrease in SAS revenues reflects the expiration in the fourth quarter of 2005 of the SAS surcharge on Regulatory Assets, which is offset by a corresponding decrease in amortization expenses on Regulatory Assets (see discussion of Depreciation & Amortization below).

The following table details total Electric Operating Revenues and Sales Margin for the three months ended March 31, 2006 and 2005:

Electric Operating Revenues and Sales Margin (000's)

	Three Months Ended March 31,			
	2006	2005	$ Change	% Change[1]
Electric Operating Revenue:				
Residential	**$ 24,221**	$ 20,992	$ 3,229	6.9%
Commercial / Industrial	**32,209**	25,820	6,389	13.6%
Total Electric Operating Revenue	**$ 56,430**	$ 46,812	$ 9,618	20.5%
Cost of Electric Sales:				
Purchased Electricity	**$ 42,912**	$ 32,326	$ 10,586	22.6%
Conservation & Load Management	**738**	800	(62)	(0.2%)
Gross Electric Sales Margin	**$ 12,780**	$ 13,686	$ (906)	(1.9%)

[1] Represents change as a percent of Total Electric Operating Revenue.

Kilowatt-hour Sales – On a composite basis, Unitil's total electric kWh sales decreased 1.2% in the three months ended March 31, 2006 compared to the same period in 2005 primarily due to the milder winter heating season in 2006 compared to 2005. The weather in the Company's service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005. Sales to residential customers and commercial and industrial (C&I) customers decreased 1.9% and 0.8%, respectively in the three month period as compared to the prior year period.

The following table details total kWh sales for the three months ended March 31, 2006 and 2005 by major customer class:

kWh Sales (000's)	Three Months Ended March 31,			
	2006	2005	Change	% Change
Residential	**183,164**	186,716	(3,552)	(1.9%)
Commercial/Industrial	**267,841**	269,958	(2,117)	(0.8%)
Total	**451,005**	456,674	(5,669)	(1.2%)

Operating Revenues - Gas

Gas Operating Revenues – Total Gas Operating Revenues increased $1.0 million, or 7.9% in the three month period ended March 31, 2006 compared to the same period in 2005. Total Gas Operating Revenues include the recovery of the costs of gas sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Gas Operating Revenues reflects higher Purchased Gas costs $1.8 million, offset by lower sales margin of $0.8 million related to lower sales volume.

Purchased Gas and C&LM revenues increased a net $1.8 million, or 13.8% of Total Gas Operating Revenues in the three month period ended March 31, 2006 compared to the same period in 2005, reflecting higher gas commodity prices and an increase in spending on energy efficiency programs that were implemented during those periods. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gross gas sales margin (Total Gas Operating Revenue less the costs of gas sales) was $3.4 million in the three month period ended March 31, 2006. This represents a decrease of $0.8 million, or 5.9% of Total Gas Operating Revenues in the three month period compared to the same period in 2005 and is attributable to lower firm therm sales volume, as discussed below.

The following table details total Gas Operating Revenues and Sales Margin for the three months ended March 31, 2006 and 2005:

Gas Operating Revenues and Sales Margin (000's)

	Three Months Ended March 31,			
	2006	2005	$ Change	% Change[1]
Gas Operating Revenue:				
Residential	**$ 7,845**	$ 7,475	$ 370	2.9%
Commercial / Industrial	**5,735**	5,205	530	4.2%
Total Firm Gas Revenue	**$ 13,580**	$ 12,680	$ 900	7.1%
Interruptible Gas Revenue	**106**	7	99	0.8%
Total Gas Operating Revenue	**$ 13,686**	$ 12,687	$ 999	7.9%
Cost of Gas Sales:				
Purchased Gas	**$ 10,186**	$ 8,424	$ 1,762	13.9%
Conservation & Load Management	**59**	71	(12)	(0.1%)
Gross Gas Sales Margin	**$ 3,441**	$ 4,192	$ (751)	(5.9%)

(1) Represents change as a percent of Total Gas Operating Revenue.

***Therm Sales* –** Firm therm sales of natural gas declined 1.9% in the three months ended March 31, 2006 compared to the same period in 2005. Sales to residential customers were 11.7% lower in the first quarter of 2006 compared to the same period in 2005 due to the extremely mild winter heating season in 2006. Sales to C&I customers were 8.0% higher in the current quarter, primarily due to a new special contract with a large industrial customer. Absent the sales associated with this new special contract, sales to C&I customers were down 13.8%, primarily reflecting the extremely mild winter weather in the first quarter of 2006 compared to the same period in 2005. The weather in the Company's service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005, as the United States experienced a record warm January.

The following table details total firm therm sales for the three months ended March 31, 2006 and 2005, by major customer class:

Firm Therm Sales (000's)

	Three Months Ended March 31,			
	2006	2005	Change	% Change
Residential	**4,902**	5,551	(649)	(11.7%)
Commercial/Industrial	**5,934**	5,495	439	8.0%
Total	**10,836**	11,046	(210)	(1.9%)

Operating Revenue - Other

Total Other Revenue increased $0.1 million, or 17.2%, in the three month period ended March 31, 2006 compared to the same period in 2005. The increase was the result of growth in revenues from the Company's unregulated energy brokering business, Usource.

The following table details total Other Revenue for the three months ended March 31, 2006 and 2005:

Other Revenue (000's)	Three Months Ended March 31,			
	2006	2005	$ Change	% Change
Other	**$ 587**	$ 501	$ 86	17.2%
Total Other Revenue	**$ 587**	$ 501	$ 86	17.2%

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $10.6 million, or 32.7%, in the three month period ended March 31, 2006 compared to the same period in 2005, reflecting higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $1.8 million, or 20.9%, in the three month period ended March 31, 2006 compared to the same period in 2005, reflecting higher gas commodity costs. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) - O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expense increased $0.2 million, or 2.9%, in the three month period ended March 31, 2006 compared to the same period in 2005. The increase reflects higher salaries and compensation costs of $0.2 million, due to annual salary and wage increases, and higher retiree and employee benefit costs of $0.1 million, partially offset by lower audit and legal fees of $0.1 million.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use electricity and natural gas more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased by $0.1 million, or 8.5%, in three month period ended March 31, 2006 compared to the same period in 2005. The decrease reflects the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense decreased $0.9 million, or 17.5%, for the three month period ended March 31, 2006 compared to the same period in 2005. This decrease was primarily due to lower amortization on regulatory assets. The Company's regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Local Property and Other Taxes - Local Property and Other Taxes increased by less than $0.1 million, or less than 1.0% for the three month period ended March 31, 2006 compared to the same period in 2005. This increase was due to higher payroll taxes partially offset by lower property tax rates.

Federal and State Income Taxes - Federal and State Income Taxes are lower by $0.3 million for the months ended March 31, 2006 compared to the same period in 2005 reflecting lower pre-tax earnings.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, net (000's)	**Three Months Ended March 31,**	
	2006	2005
Interest Expense		
Long-term Debt	**$ 2,320**	$ 2,102
Short-term Debt	**305**	216
Regulatory Liabilities	**42**	39
Subtotal Interest Expense	**2,667**	2,357
Interest Income		
Regulatory Assets	**(728)**	(587)
AFUDC and Other	**(26)**	(15)
Subtotal Interest Income	**(754)**	(602)
Total Interest Expense, net	**$ 1,913**	$ 1,755

Interest Expense, net increased by $0.2 million, or 9.0% in the three month period ended March 31, 2006 compared to the same period in 2005. Interest expense on long-term borrowings in the three month period ended March 31, 2006 increased $0.2 million compared to the prior year period due to the refinancing of variable rate short-term debt with fixed rate long-term debt. In December 2005 Unitil's Massachusetts utility subsidiary, FG&E issued $15 million of unsecured long-term notes to institutional investors. Interest expense on short-term debt increased $0.1 million in the three month period ended March 31, 2006 compared to the same period in 2005 primarily due to higher average short-term interest rates. These increases in interest expense were partially offset by an increase in interest income on regulatory assets of $0.1 million primarily due to higher carrying charges on regulatory assets.

CAPITAL REQUIREMENTS

Cash provided by operating activities was $0.7 million during the First Quarter of 2006, a decrease of $8.1 million over the comparable period in 2005. Net Income was $0.7 million lower in the first quarter of 2006 compared to 2005. Cash required for Accounts Payable increased $4.9 million compared to last year mainly due to the higher costs of purchasing electricity and natural gas for our customers. Cash from Accrued Revenue decreased $2.0 million quarter over quarter mainly due to higher energy costs, which will be collected from customers in future periods. During the First Quarter of 2006 as compared to the same quarter in the prior year, Taxes Payable declined by $1.5 million dollars, reflecting higher estimated tax payments in 2006 compared to the refunds received in the first quarter of 2005. In addition, uses of cash for Deferred Restructuring Costs declined by $1.7 million in the first quarter of 2006 compared to the same quarter last year. Deferred Restructuring Costs are regulatory assets that will be recovered from customers in future periods. All other changes in cash flows from operating activities were a net decrease of $0.7 million in cash provided by operating activities.

Cash used in investing activities was $5.6 million for the three months ended March 31, 2006 and increased by $1.2 million over the comparable period in 2005. Annual capital expenditures are presently budgeted to be $37.2 million in 2006 compared to $24.4 million expended in 2005. These 2006 capital expenditures include approximately $9.5 million of cash outlays for the Automated Meter Infrastructure projects, which are expected to be completed in 2007. Capital expenditure projections are subject to changes during the fiscal year.

Cash flows provided by financing activities were $3.9 million in the first three months of 2006. In the comparable period of 2005 cash used in financing activities amounted to $3.2 million, a net change between the two periods of $7.2 million. Cash provided for financing activities in the current period includes the proceeds from short-term bank borrowings of $6.0 million as compared to the repayment of $1.4 million of short-term bank borrowings during the same period in 2005. The current period reflects the early repurchase of $0.2 million of preferred stock. Both periods reflect the payment of dividends to shareholders of approximately $2.0 million. During the First Quarter of 2006 and 2005, normal sinking fund payments amounted to approximately $0.1 million during both periods. Both periods include the proceeds of approximately $0.3 million received from the sale of Unitil Common Stock through the Dividend Reinvestment and Stock Purchase Plan and 401(k) plans.

At March 31, 2006 Unitil had an aggregate of $44.0 million in unsecured revolving lines of credit through three banks. The Company expects to renew its lines of credit annually on or about June 30, 2006 and anticipates that it will be able to secure, renew or replace its revolving lines of credit in the future in accordance with its projected requirements. Average daily short-term borrowings during the first three months of 2006 were approximately $23.5 million, a decrease of approximately $2.0 million over the comparable period in 2005. At March 31, 2006, the Company had available approximately $19.3 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $24.7 million. In addition, Unitil had $2.2 million in cash at March 31, 2006.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2006, there are $6.0 million of guarantees outstanding and the longest term guarantee extends through October 24, 2007.

Critical Accounting Policies

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 22, 2006.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded

Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet. The Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In management's opinion, the Company's regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates approved by state and federal regulatory commissions. These regulated rates are applied to customers' accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Pension and Postretirement Benefit Obligations - The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with FASB Statement No. 87, "Employers' Accounting for Pensions" and FASB Statement No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions." In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions.

The Company's reported costs of providing pension and PBOP benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and PBOP costs (collectively "postretirement costs") are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements. See Note 8.

Pension expense is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

Income Taxes - Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under FASB Statement No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts.

Depreciation - Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets.

Commitments and Contingencies - The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or loss that will ultimately be resolved when one or more future events occur or fail to occur.

Refer to "Recently Issued Accounting Pronouncements" in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company's debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company's short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company's interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company's short-term borrowings for the three months ended March 31, 2006 and March 31, 2005 were 5.00% and 3.05%, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(000's except common shares and per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2006	2005
Operating Revenues		
Electric	**$ 56,430**	$ 46,812
Gas	**13,686**	12,687
Other	**587**	501
Total Operating Revenues	**70,703**	60,000
Operating Expenses		
Purchased Electricity	**42,912**	32,326
Purchased Gas	**10,186**	8,424
Operation and Maintenance	**6,092**	5,918
Conservation & Load Management	**797**	871
Depreciation and Amortization	**4,179**	5,066
Provisions for Taxes:		
Local Property and Other	**1,497**	1,486
Federal and State Income	**1,105**	1,405
Total Operating Expenses	**66,768**	55,496
Operating Income	**3,935**	4,504
Non-Operating (Income) Expenses	**(21)**	39
Income Before Interest Expense	**3,956**	4,465
Interest Expense, Net	**1,913**	1,755
Net Income	**2,043**	2,710
Less: Dividends on Preferred Stock	**30**	39
Earnings Applicable to Common Shareholders	**$ 2,013**	$ 2,671
Average Common Shares Outstanding - Basic	**5,576,551**	5,533,123
Average Common Shares Outstanding - Diluted	**5,590,904**	5,549,223
Earnings Per Common Share (Basic and Diluted)	**$ 0.36**	$ 0.48
Dividends Declared Per Share of Common Stock	**$ 0.690**	$ 0.690

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(000's)

	(UNAUDITED) March 31, 2006	(UNAUDITED) March 31, 2005	(AUDITED) December 31, 2005
ASSETS:			
Utility Plant:			
Electric	**$ 237,244**	$ 225,763	$ 234,153
Gas	**58,988**	53,659	58,675
Common	**25,633**	27,104	26,515
Construction Work in Progress	**7,251**	3,944	5,624
Total Utility Plant	**329,116**	310,470	324,967
Less: Accumulated Depreciation	**113,825**	105,697	111,646
Net Utility Plant	**215,291**	204,773	213,321
Current Assets:			
Cash	**2,213**	4,164	3,207
Accounts Receivable – Net of Allowance for Doubtful Accounts of $1,025, $580 and $550	**26,424**	21,834	23,551
Accrued Revenue	**6,388**	6,128	8,905
Refundable Taxes	**---**	---	351
Materials and Supplies	**2,600**	1,952	3,675
Prepayments and Other	**1,296**	1,501	1,612
Total Current Assets	**38,921**	35,579	41,301
Noncurrent Assets:			
Regulatory Assets	**173,639**	193,381	179,719
Prepaid Pension Costs	**10,391**	10,505	11,099
Debt Issuance Costs	**2,368**	2,239	2,343
Other Noncurrent Assets	**3,240**	4,579	2,218
Total Noncurrent Assets	**189,638**	210,704	195,379
TOTAL	**$ 443,850**	$ 451,056	$ 450,001

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(000's)

	(UNAUDITED) March 31, 2006	(UNAUDITED) March 31, 2005	(AUDITED) December 31, 2005
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 94,767**	$ 93,496	$ 96,283
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**1,880**	2,113	2,102
Long-Term Debt, Less Current Portion	**125,282**	110,600	125,365
Total Capitalization	**222,154**	206,434	223,975
Current Liabilities:			
Long-Term Debt, Current Portion	**316**	290	308
Capitalized Leases, Current Portion	**249**	325	261
Accounts Payable	**14,692**	15,224	20,600
Short-Term Debt	**24,725**	24,275	18,700
Dividends Declared and Payable	**1,985**	1,967	50
Refundable Customer Deposits	**2,089**	1,664	2,031
Taxes Payable	**1,844**	2,742	---
Interest Payable	**2,441**	2,195	1,353
Other Current Liabilities	**1,674**	1,098	2,597
Total Current Liabilities	**50,015**	49,780	45,900
Deferred Income Taxes	**50,754**	54,042	52,297
Noncurrent Liabilities:			
Power Supply Contract Obligations	**107,669**	134,062	114,906
Capitalized Leases, Less Current Portion	**267**	146	324
Other Noncurrent Liabilities	**12,991**	6,592	12,599
Total Noncurrent Liabilities	**120,927**	140,800	127,829
TOTAL	**$ 443,850**	$ 451,056	$ 450,001

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF C ASH FLOWS
(000's)
(UNAUDITED)

	Three Months Ended March 31,	
	2006	2005
Cash Flow from Operating Activities:		
Net Income	**$ 2,043**	$ 2,710
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**4,179**	5,066
Deferred Taxes	**(1,352)**	(1,772)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**(2,873)**	(3,715)
Accrued Revenue	**1,586**	3,626
Taxes Refundable / Payable	**2,195**	3,719
Materials and Supplies	**1,075**	1,128
Prepayments and Other	**316**	270
Accounts Payable	**(5,908)**	(1,025)
Refundable Customer Deposits	**58**	119
Interest Payable	**1,088**	867
Other Current Liabilities	**(923)**	(269)
Deferred Restructuring and Other Charges	**(444)**	(2,161)
Other, net	**(346)**	262
Cash Provided by Operating Activities	**694**	8,825
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	**(5,626)**	(4,444)
Cash (Used in) Investing Activities	**(5,626)**	(4,444)
Cash Flows from Financing Activities:		
Issuance (Repayment) of Short-Term Debt, net	**6,025**	(1,400)
Repayment of Long-Term Debt	**(75)**	(70)
Dividends Paid	**(1,966)**	(1,953)
Issuance of Common Stock	**245**	299
Retirement of Preferred Stock	**(222)**	---
Repayment of Capital Lease Obligations	**(69)**	(125)
Cash Provided by (Used in) Financing Activities	**3,938**	(3,249)
Net Increase (Decrease) in Cash	**(994)**	1,132
Cash at Beginning of Period	**3,207**	3,032
Cash at End of Period	**$ 2,213**	$ 4,164
Supplemental Cash Flow Information:		
Interest Paid	**$ 1,542**	$ 1,460
Income Taxes Paid (Refunded)	**803**	(478)

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICA NT ACCOUNTING POLICI ES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three months ended March 31, 2006 are not necessarily indicative of results to be expected for the year ending December 31, 2006. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2005, as filed with the SEC on February 22, 2006, for a description of the Company's Basis of Presentation.

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES) (formed in 2002 by the combination and merger of Unitil's former utility subsidiaries Concord Electric Company and Exeter & Hampton Electric Company), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In February 2006, the FASB issued FASB Statement No. 155, "Accounting for Certain Hybrid Financial Instruments", (SFAS No. 155), which amends FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities", (SFAS No.133) and FASB Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities", (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. Additionally, SFAS No. 155 establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation and clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives. SFAS No. 155 also amends SFAS No. 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. The Company will adopt SFAS No. 155 and does not expect that it will have an impact on the Company's Consolidated Financial Statements.

In February 2006, the FASB issued FASB Staff Position No. FAS 123(R)-4, (FSP 123(R)-4), "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement Upon the Occurrence of a Contingent Event". FSP 123(R)-4 addresses the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event and amends paragraphs 32 and A229 of revised FASB Statement No. 123(R), "Share-Based Payment", (SFAS No. 123(R)), which was issued in December 2004. SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. The Company uses the fair value method for share-based payment awards and therefore the provisions of SFAS No. 123(R) will have no impact on the Consolidated Financial Statements. The Company has adopted the provisions of FSP 123(R)-4 and it did not have an impact on the Company's Consolidated Financial Statements.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46) and in December 2003 issued a revised FIN 46. This interpretation clarified the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," and replaced the current accounting guidance relating to the consolidation of variable interest entities (VIE's) established on the basis of contractual, ownership or other monetary interests. The Company reviewed its investments and affiliations and determined that it had a variable interest in the Unitil Retiree Trust (URT), a special purpose entity established January 1993. URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. URT was under the direction of an independent Board of Trustees whose voting members were comprised of former employees of the Company, elected by and from the membership of URT. In the fourth quarter of 2003, URT was dissolved by a vote of its trustees and the Company assumed the obligations of URT as of October 1, 2003. There are no other entities identified by the Company that qualify as VIE's under FIN 46.

Reclassifications - Certain amounts previously reported have been reclassified to conform to current year - presentation.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
03/23/06	05/15/06	05/01/06	$ 0.345
01/12/06	02/15/06	02/01/06	$ 0.345
09/23/05	11/15/05	11/01/05	$ 0.345
06/17/05	08/15/05	08/01/05	$ 0.345
03/24/05	05/13/05	04/29/05	$ 0.345
01/13/05	02/15/05	02/01/05	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first quarter of 2006, the Company sold 9,967 shares of its Common Stock, at an average price of $24.60 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $245,000 were used to reduce short-term borrowings.

During the first quarter of 2005, the Company sold 10,921 shares of its Common Stock, at an average price of $27.38 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of $299,045 were used to reduce short-term borrowings.

On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company Common Stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided in the Plan. Awards fully vest over a period of four years at a rate of 25% each year. During the vesting period, dividends on restricted shares underlying the Award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the Award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit. On February 16, 2006, 14,375 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $366,563. On March 8, 2005, 10,900 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $299,423. On April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $293,715. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period.

Details on preferred stock at March 31, 2006, March 31, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) March 31, 2006	(Unaudited) March 31, 2005	(Audited) December 31, 2005
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 225**	$ 225	$ 225
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**892**	899	892
8.00% Series, $100 Par Value	**988**	1,214	1,210
Total Preferred Stock	**$ 2,105**	$ 2,338	$ 2,327

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at March 31, 2006, March 31, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) March 31,		(Audited) December 31,
	2006	2005	2005
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**$ 15,000**	$ 15,000	$ 15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000	15,000
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19,000**	19,000	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000	14,000
6.79% Notes, Due October 15, 2025	**10,000**	10,000	10,000
5.90% Notes, Due December 15, 2030	**15,000**	---	15,000
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5,598**	5,890	5,673
Total	**125,598**	110,890	125,673
Less: Installments due within one year	**316**	290	308
Total Long-term Debt	**$ 125,282**	$ 110,600	$ 125,365

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2006 there are $6.0 million of guarantees outstanding and these guarantees extend through October 24, 2007. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three months ended March 31, 2006 and March 31, 2005:

Three Months Ended March 31, 2006 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$ 56,430**	**$ 13,686**	**$ ---**	**$ 587**	**$ 70,703**
Segment Profit (Loss)	**1,262**	**727**	**125**	**(101)**	**2,013**
Identifiable Segment Assets	**319,163**	**101,900**	**21,455**	**1,332**	**443,850**
Capital Expenditures	**5,210**	**423**	**(7)**	**---**	**5,626**

Three Months Ended March 31, 2005 (000's)					
Revenues	$ 46,812	$ 12,687	$ ---	$ 501	$ 60,000
Segment Profit (Loss)	1,410	1,178	101	(18)	2,671
Identifiable Segment Assets	332,388	96,815	20,964	889	451,056
Capital Expenditures	4,025	404	15	---	4,444

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

Overview – Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil's utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the MDTE, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party vendors. Most customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next five to seven years, is $146.1 million as of March 31, 2006 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E – Electric Division – FG&E's primary business is providing electric distribution service. Its current retail electric distribution rates were approved by the MDTE in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of March 31, 2006, approximately 56 percent of FG&E's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $38.3 million at March 31, 2006, and $35.9 million at March 31, 2005, and is expected to be recovered in FG&E's rates over the next five to seven years. In addition, as of March 31, 2006, FG&E had recorded on its balance sheets $55.9 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

Recovery of the deferred amounts described above will be made pursuant to a Settlement Agreement among FG&E, the Massachusetts Office of the Attorney General (Attorney General), and representatives of industrial and low-income customers. The Settlement Agreement, which was approved by the MDTE in 2005, provides for a rate path to allow recovery of FG&E's deferred stranded costs.

On March 7, 2006, the MDTE approved FG&E's 2003 and 2004 annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. FG&E's 2005 filing, which is subject to investigation, is pending. Management believes that this filing will be approved without material changes or adjustments.

FG&E – Gas Division – FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDTE in 2002. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

FG&E – Other – On October 27, 2004, the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism to provide for the recovery of costs associated with the Company's employee pension benefits and PBOP expenses. FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism provides for an annual filing and rate adjustment with the MDTE. As of March 31, 2006, FG&E has recorded a regulatory asset of $2.7 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets.

On November 30, 2005, the MDTE announced a change in its method for recovery of gas cost-related bad debt, and determined that it would allow for full recovery of these costs on a reconciling basis. On December 15, 2005, FG&E filed a revised CGAC tariff reflecting this change which was approved effective January 1, 2006. FG&E also requested approval to recover its under-recovered gas cost-related bad debt for 2005 of approximately $164,000. On February 24, 2006, FG&E made a similar filing for its electric division, seeking approval to recover its actual electric supply-related bad debt through Default Service rates, effective January 1, 2006, and to recover its under-recovered electric supply-related bad debt for 2005 of approximately $84,000. On April 7, 2006, the MDTE consolidated the gas and electric requests for simultaneous review. A decision on these requests is expected in 2006.

UES – UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were established under a 2002 restructuring settlement agreement. On May 1, 2004, these distribution rates were increased by $1.0 million to provide for the recovery of PBOP costs. As the provider of last resort, UES also provides its customers with electric power through either Transition or Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES' Transition Service supply obligation for all rate classes ends on April 30, 2006. On May 1, 2006, customers previously on Transition Service will automatically be placed on Default Service. Under a NHPUC approved settlement with the Office of the Consumer Advocate and the NHPUC Staff, UES will procure Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of March 31, 2006, approximately 86 percent of UES' electric load was served by Transition Service. The remaining portion was served by competitive third party suppliers.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery and Transition and Default Service, including certain charges that are subject to annual or periodic reconciliation or future review. As of March 31, 2006, UES had recorded on its balance sheets $51.8 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately five years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 17, 2006, UES made its third annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2006, including reconciliation of prior year costs and revenues for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. The NHPUC's review of this filing is pending.

On December 11, 2004, UES filed with the NHPUC a Petition for an accounting order to defer certain pension costs above those included in its base rates, until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007 (also see Note 8 below). On April 7, 2005, the NHPUC issued an order denying UES' Petition for an accounting order. In its analysis denying UES' request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that the size and impact of increased pension expense is not clear and that a full examination of UES' income and expenses would be undertaken when UES files a rate case. As discussed below, the Company filed a full base rate case on November 4, 2005, which included a request for recovery of Pension/PBOP costs through a reconciling mechanism, the Pension/PBOP Adjustment Charge (PAC). UES' regulatory history with the NHPUC regarding this issue taken together with ratemaking precedent concerning pension cost recovery leads management to conclude that the pension costs are probable of recovery under the requirements of Paragraph 9 of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation. As of March 31, 2006, UES has recorded deferred pension costs of $1.2 million.

On November 4, 2005, UES filed a request for a base rate increase of $4.65 million with the NHPUC. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving the request for temporary rates. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the pending base rate case. The Company cannot determine the ultimate outcome of this proceeding.

FERC – Wholesale Power Market Restructuring – FG&E, UES and Unitil Power are members of the NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. The regional bulk power system is operated by an independent corporate entity, the ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a RTO was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO effective February 1, 2005. Several parties have appealed various issues associated with the FERC's approval of the RTO to Federal District Court of Appeals. Those proceedings are ongoing.

On March 1, 2004, ISO-NE filed a proposal to implement LICAP in New England to allow for the imposition of incentive pricing for transmission constrained areas. UES and FG&E intervened in the proceeding. On April 11, 2006, a contested Settlement was submitted by the FERC Settlement Judge to the FERC. The Settlement would resolve the LICAP proceeding. It proposes transition payments for capacity until a Forward Capacity Market can be implemented, possibly by 2010. The Settlement requests action by the FERC by June 30, 2006, for implementation by December 2006. This case continues to be contested at the FERC.

The formation of an RTO, LICAP and other wholesale market changes, including changes to transmission rates, is not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy costs approved by the MDTE and NHPUC. It is possible, however, that retail rates will be significantly increased over the next several years if LICAP is implemented consistent with the Initial Decision.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of March 31, 2006, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site – The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan (MCP) that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E is in the process of developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

On May 13, 2004 FG&E discovered an unauthorized excavation by another property owner on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated onto property owned by FG&E. FG&E promptly reported this discovery to the DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. The Completion Report for this release was submitted May 9, 2005.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1822 through 1978. In addition, any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Note 8: Pension and Postretirement Benefit Plans

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

Defined Benefit Pension Plan – The Company sponsors the Unitil Corporation Retirement Plan (the Plan), a defined benefit pension plan covering substantially all its employees. Under the Plan retirement benefits are based upon an employee's level of compensation and length of service. The Company records annual expense and accounts for its defined benefit pension plan in accordance with FASB Statement No. 87, "Employers' Accounting for Pensions", (SFAS No. 87).

In December 2003 and 2002, UES and FG&E filed requests with their respective state regulatory commissions for approval of accounting orders to mitigate certain accounting requirements related to pension plan assets which had been triggered by the substantial decline in the capital markets. UES and FG&E were granted approval of this regulatory accounting treatment in January 2003 and 2004. As a result of these approvals, the Company has recorded as a Regulatory Asset the amount of the Plan's unfunded Accumulated Benefit Obligation (ABO) plus one dollar. These approvals allow UES and FG&E to treat their Additional Minimum Liability (AML) as Regulatory Assets under FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation", (SFAS No. 71) and avoid the reduction in equity through other comprehensive income that would otherwise be required by SFAS No. 87.

On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the Pension / PBOP Adjustment Factor (PAF), to recover the costs associated with the Company's pension, and postretirement benefits other than pensions (PBOP), costs on an annually reconciling basis. As a result of this order, FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and FASB Statement No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions", (SFAS No. 106) and amortizes increases and /or decreases in that deferral balance into the PAF for recovery over a three year period. The PAF provides for an annual filing and rate adjustment with the MDTE and requires that carrying charges on prepaid or (accrued) pension and PBOP assets and liabilities be collected from, or refunded to, utility customers. In 2005, FG&E received approval of its first annual filing and rate adjustment.

The Company initiated similar discussions for a reconciling rate mechanism for the pension costs of UES with the NHPUC. On December 11, 2004, UES filed with the NHPUC a Petition for an Accounting Order to defer certain pension costs above those included in its base rates until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007. On April 7, 2005, the NHPUC issued an order denying UES' Petition for an accounting order. In its analysis denying UES' request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that the size and impact of increased pension expense is not clear and that a full examination of UES' income and expenses would be undertaken when UES files a rate case. As discussed below, the Company filed a full base rate case on November 4, 2005, which included a request for recovery of Pension/PBOP costs through a reconciling mechanism, the PAC. UES' regulatory history with the NHPUC regarding this issue taken together with ratemaking precedent concerning pension cost recovery leads management to conclude that the pension costs are probable of recovery under the requirements of Paragraph 9 of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation. As of March 31, 2006, UES has recorded deferred pension costs of $1.2 million.

On November 4, 2005, UES filed a request for a base rate increase of $4.65 million with the NHPUC. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving the request for temporary rates. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the pending base rate case. The Company cannot determine the ultimate outcome of this proceeding.

The following tables show the components of net periodic pension cost (income), (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

	Three Months Ended March 31, 2006	2005
Components of NPPC (000's)		
Service Cost	**$ 450**	$ 347
Interest Cost	**787**	756
Expected Return on Plan Assets	**(912)**	(865)
Amortization of Prior Service Cost	**27**	25
Amortization of Net (Gain) Loss	**355**	222
Subtotal NPPC	**707**	485
Amounts Capitalized and Deferred	**(577)**	(397)
NPPC Recognized	**$ 130**	$ 88

Included in the amounts above for Amounts Capitalized and Deferred are $307,000 and $213,000 recorded as Regulatory Assets on the Company's Balance Sheets for 2005 and 2004, respectively. The remaining amounts represent amounts capitalized to construction overheads.

Key Assumptions (Weighted Average)	**2006**	2005
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50% (1)
Rate of Compensation Increase	**3.50%**	3.50%
Used to Determine NPPC:		
Discount Rate	**5.50%**	6.50% (1)
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%
Rate of Compensation Increase	**3.50%**	3.50%

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions – As of March 31, 2006, the Company has not yet made any contributions to the Plan for 2006. The Company is required to make a minimum contribution to its pension plan this year in the amount of $0.8 million. The Company contributed $2.5 million in 2005.

Postretirement Benefits - The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) primarily to provide health care and life insurance benefits to active employees. Prior to October 1, 2003, the Company funded certain postretirement benefits through the Unitil Retiree Trust (URT). URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. Effective January 1, 2004, the PBOP Plan was amended to provide certain healthcare and life insurance benefits, which were previously provided by the URT. The Company has established Voluntary Employee Benefit Trusts, into which it funds contributions to the PBOP Plan.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS No. 106-1) and Statement No. 106-2 (SFAS No. 106-2), "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary's annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS No. 106-1 and SFAS No. 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation and how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods. On January 28, 2005, the final Medicare Part D Prescription Drug Rules were posted to the Federal Register. Based on these rules, the Company's estimated

PBOP Projected Benefit Obligation was reduced by $5.1 million. Also, the Company has estimated that its annual PBOP costs will be reduced by $0.4 million under the Act. These reductions are reflected in the Company's Consolidated Financial Statements. The Company's health care insurance provider has concluded that the Company's PBOP Plan is equal to or better than standard Medicare Part D coverage. Additionally, the Company's recognition of the Act is not expected to have any impact on the rate of participation in the PBOP Plan or per capita claims.

As discussed above, on October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis.

On March 15, 2004 UES filed a petition with the NHPUC for recovery of PBOP costs. UES proposed an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004. The NHPUC approved this filing, effective May 1, 2004.

As discussed above, on November 4, 2005, UES filed a request for a base rate increase of $4.65 million. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving this request. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding.

The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended March 31,	
	2006	2005
Components of NPPBC (000's)		
Service Cost	**$ 292**	$ 222
Interest Cost	**450**	456
Expected Return on Plan Assets	**(28)**	(15)
Amortization of Prior Service Cost	**340**	365
Amortization of Transition (Asset) Obligation	**5**	5
Amortization of Net (Gain) Loss	**---**	(16)
Subtotal NPPBC	**1,059**	1,017
Amounts Capitalized and Deferred	**(482)**	(482)
NPPBC Recognized	**$ 577**	$ 535

Included in the amounts above for Amounts Capitalized and Deferred are $71,000 and $83,000 recorded as Regulatory Assets on the Company's Balance Sheets for 2005 and 2004, respectively. The remaining amounts represent amounts capitalized to construction overheads.

Weighted-Average Assumptions	**2006**	2005
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50% (1)
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	7.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013
Used to Determine NPPBC:		
Discount Rate	**5.50%**	6.50% (1)
Expected Long-Term Rate of Return on Plan Assets	**8.50%/5.50%** (2)	8.50%/5.50% (2)
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

(2) Funding of the PBOP Plan is made into two VEBT's; one is a union VEBT and the other is a non-union VEBT. The expected long-term rate of return on plan assets for the union VEBT is 8.50%. The non-union VEBT is subject to income taxes and therefore the expected long-term rate of return on plan assets is 5.50%, reflecting the effect of taxes.

Employer Contributions – As of March 31, 2006, the Company has made $0.5 million of contributions to the PBOP Plan. The Company presently anticipates contributing an additional $2.1 million to fund the Plan in 2006 for an estimated total of $2.6 million. The Company contributed $2.5 million in 2005.

Supplemental Executive Retirement Plan - The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors.

The components of net periodic SERP cost are as follows:

	Three Months Ended March 31,	
	2006	2005
Components of NPPC (000's)		
Service Cost	**$ 36**	$ 24
Interest Cost	**26**	20
Expected Return on Plan Assets	**---**	---
Amortization of Prior Service Cost	**---**	---
Amortization of Transition Obligation	**4**	4
Amortization of Net Loss	**10**	1
Net Periodic SERP Cost	**$ 76**	$ 49

Employer Contributions – As of March 31, 2006, the Company has made payments of $18,000 to beneficiaries. The Company presently anticipates making additional benefit payments of $54,000 in 2006 for a total of $72,000.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the “Interest Rate Risk” and “Market Risk” sections of Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company’s Form 10-K for the year-ended December 31, 2005 as filed with the Securities and Exchange Commission on February 22, 2006.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended March 31, 2006.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
1/1/06 – 1/31/06	---	---	---	n/a
2/1/06 – 2/28/06	---	---	---	n/a
3/1/06 – 3/31/06	122	$25.70	122	n/a
Total	122	$25.70	122	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated April 28, 2006 Announcing Earnings For the Quarter Ended March 31, 2006	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: April 28, 2006

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: April 28, 2006

/s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING

(000's except for per share data)

(UNAUDITED)

	Three Months Ended March 31,	
(000's, except per share data)	**2006**	2005
Net Income	**$2,043**	$2,710
Less: Dividend Requirements on Preferred Stock	**30**	39
Net Income Applicable to Common Stock	**$2,013**	$2,671
Weighted Average Number of Common Shares Outstanding – Basic	**5,576,551**	5,533,123
Dilutive Effect of Stock Options and Restricted Stock	**14,353**	16,100
Weighted Average Number of Common Shares Outstanding – Diluted	**5,590,904**	5,549,223
Earnings Per Share – Basic	**$0.36**	$0.48
Earnings Per Share – Diluted	**$0.36**	$0.48

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2006

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any un true statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in thi s report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a -15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material informatio n relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance wit h generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth f iscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2006

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2006

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending March 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Controller and Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	April 28, 2006
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	April 28, 2006
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	April 28, 2006

Exhibit 99.1

For Immediate Release

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports First Quarter Earnings

Hampton, NH – April 28, 2006: Unitil Corporation (AMEX: UTL) (www.unitil.com) today announced net income of $2.0 million for the first quarter of 2006. Earnings per common share were $0.36 for the first quarter of 2006 compared with $0.48 in the first quarter of 2005, primarily reflecting lower gas and electric unit sales due to milder winter temperatures in 2006. The National Oceanic and Atmospheric Administration reported that the United States experienced the warmest January on record in 2006. Heating degree days in the Company's service territories in the first quarter of 2006 were 12% lower than in the same period for 2005.

The milder weather caused unit sales of natural gas to residential customers to decline 11.7% in the three months ended March 31, 2006 compared to the same period in 2005. Gas sales to commercial and industrial ("C&I") customers were up 8.0% in the three months ended March 31, 2006 compared to the same period in 2005, primarily due to a new special contract with a large industrial customer. Absent the sales associated with this special contract, sales to C&I customers were down 13.8%, reflecting the milder weather.

Total electric kWh sales, which are less sensitive to weather than natural gas sales, decreased 1.2% in the three months ended March 31, 2006 compared to the same period in 2005. Sales to residential customers and C&I customers were down 1.9% and 0.8%, respectively, in the three months ended March 31, 2006 compared to the same period in 2005.

"Our first quarter results reflect the significant impact weather has on our business," said Unitil Chairman, President and Chief Executive Officer Robert G. Schoenberger. "The diversity of our service territories and underlying growth in our distribution business are mitigating factors in what should be the short-term impact of the unpredictable New England weather cycle."

Total O&M expense increased $0.2 million, or 2.9%, in the three month period ended March 31, 2006 compared to the same period in 2005. The increase reflects higher salaries and compensation costs of $0.2 million and higher retiree and employee benefit costs of $0.1 million, partially offset by lower audit and legal fees of $0.1 million.

Depreciation, Amortization, Taxes and Other decreased $1.2 million in the first three months of 2006 compared to the same period in 2005, primarily due to lower amortization on regulatory assets and lower income taxes. The Company's regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the fourth quarter of 2005. In the first three months of 2006, Interest Expense, net, increased by $0.2 million as compared to the same period in 2005 due to higher borrowings and interest rates compared to last year.

Unitil's New Hampshire utility operating subsidiary, Unitil Energy Systems, Inc. ("UES") filed a request for a base rate increase of $4.65 million with the New Hampshire Public Utilities Commission ("NHPUC") which established temporary rate relief at current rate levels, effective January 1, 2006. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with a NHPUC order anticipated before the end of 2006. The Company will continue to recognize UES' utility revenues at current rates until such time as the outcome of the rate case can be more clearly determined.

Also in the first quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

Unitil is a public utility holding company with subsidiaries providing electric service in New Hampshire and electric and gas service in Massachusetts and energy services throughout the Northeast. Its subsidiaries include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Unitil Power Corp., Unitil Realty Corp., Unitil Service Corp. and its unregulated business segment Unitil Resources, Inc. Usource L.L.C. is a subsidiary of Unitil Resources, Inc.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

The following table details total kilowatt-hour (kWh) sales of electricity for the three months ended March 31, 2006 and 2005, by major customer class.

kWh Sales (000's)	**Three Months Ended March 31,**		
	2006	2005	% Change
Residential	183,164	186,716	(1.9%)
Commercial/Industrial	267,841	269,958	(0.8%)
Total	451,005	456,674	(1.2%)

The following table details total firm therm sales of natural gas for the three months ended March 31, 2006 and 2005, by major customer class.

Firm Therm Sales (000's)	**Three Months Ended March 31,**		
	2006	2005	% Change
Residential	4,902	5,551	(11.7%)
Commercial/Industrial	5,934	5,495	8.0%
Total	10,836	11,046	(1.9%)

Unitil Corporation

(Amounts In Thousands, except Shares and Per Share Data) (Unaudited)

Condensed Financial Data	Three Months Ended March 31, 2006	2005
Operating Revenues	$ 70,703	$ 60,000
Purchased Electric and Gas and Conservation & Load Management	53,895	41,621
Operation & Maintenance	6,092	5,918
Depreciation, Amortization, Taxes & Other	6,781	7,957
Operating Income	3,935	4,504
Interest Expense, Net	1,913	1,755
Other (Income) Expense	(21)	39
Net Income	2,043	2,710
Preferred Dividends	30	39
Net Income Applicable to Common Stock	$ 2,013	$ 2,671

Earnings per Common Share		
Net Income Applicable to Common Stock	$ 0.36	$ 0.48
Average Common Shares Outstanding - Diluted	5,590,904	5,549,223

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended June 30, 2006

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X__

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 27, 2006
Common Stock, No par value	5,631,792 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended June 30, 2006

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

SAFE HARBOR CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Unitil Corporation and subsidiaries' (Unitil or the Company) future operations, are forward-looking statements.

These statements include declarations regarding Management's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

? Variations in weather;
? Changes in the regulatory environment;
? Customers' preferences on energy sources;
? Interest rate fluctuation and credit market concerns;
? General economic conditions;
? Increased competition; and
? Fluctuations in supply, demand, transmission capacity and prices for energy commodities.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

Earnings Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $1.4 million for the second quarter of 2006, a decrease of $0.1 million compared to the same period in 2005. Earnings per common share were $0.25 for the second quarter of 2006, a decrease of $0.02 per share compared with earnings of $0.27 per share for the second quarter of 2005. Earnings for the second quarter of 2006 reflect higher interest and net operating expenses and lower gas sales margins, partially offset by improved margins on electric sales due to the recognition, in the second quarter of 2006, of estimated rate relief for the Company's New Hampshire utility subsidiary.

For the six month period ended June 30, 2006, net income was $3.4 million compared to $4.2 million in the first six months of 2005. Through the first six months, earnings per share were $0.61 for 2006 compared with $0.75 per share for 2005, reflecting higher net operating expenses and interest expense and lower electric and gas sales margins in 2006.

Total electric sales in the three and six months ended June 30, 2006 were down 0.3% and 0.8%, respectively, in the Company's utility service territories. Sales to residential customers increased 0.8% in the three month period ended June 30, 2006 compared to the prior year but decreased 0.7% overall in the six month period compared to the prior year primarily due to a significantly milder winter heating season in 2006. Sales to commercial and industrial (C&I) customers decreased 1.0% and 0.9% in the three and six month periods, respectively, compared to the prior year periods due to lower consumption for heating and production purposes.

The Company's New Hampshire utility operating subsidiary, Unitil Energy Systems, Inc. (UES) filed a request for a base rate increase of $4.65 million with the New Hampshire Public Utilities Commission (NHPUC) which established temporary rate relief at current rate levels, effective January 1, 2006. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The rate filing is currently under review, with a NHPUC order anticipated before the end of 2006. Based on the temporary rate order and the current status of proceedings, management has recorded an estimate of expected revenue and expenses for the first six months of 2006. The estimate includes $1.7 million in estimated revenue and $1.0 million in estimated operating expenses and taxes, a net increase to operating income of $0.7 million.

Electric sales margin increased $0.5 million in the three month period ended June 30, 2006 compared to the same period in 2005. For the six month period ended June 30, 2006, electric sales margin decreased $0.3 million compared to the same period in 2005. The lower electric margin for the six months ended June 30, 2006 reflects decreases of $1.8 million related to lower Seabrook Amortization Surcharge (SAS) and other revenues and $0.2 million related to lower sales volume offset by the recognition of $1.7 million of revenue based on the Company's pending rate filing in New Hampshire, discussed above. This decrease in SAS revenues reflects the expiration in the fourth quarter of 2005 of the SAS tariff on Regulatory Assets, which is largely matched by a decrease in amortization expenses on Regulatory Assets (see discussion of Depreciation & Amortization below).

Total sales of natural gas increased 28.9% in the three months ended June 30, 2006 compared to the same period in 2005 and increased 7.7% in the six months ended June 30, 2006 compared to the same period in 2005. The increases in both of these periods were due to a new contract with a large industrial customer. Absent the sales from this new contract, sales to C&I customers were approximately 9.1% and 11.7% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Gas sales to residential customers were 13.0% and 11.5% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The declines in residential and C&I sales reflect lower average energy usage by customers during a period of higher energy prices and significantly milder winter weather in 2006. The weather in the Company's service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005, and the country as a whole experienced a record warm January.

Gas sales margin decreased $0.3 million and $0.9 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The decreases in gas margin are attributable to lower sales volume on C&I and residential sales, as discussed above. The Massachusetts Department of Telecommunications and Energy (MDTE) is in the process of approving the margin earned by the Company under the new contract, discussed above. Accordingly, pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin.

Total O&M expense increased $1.0 million and $1.1 million, respectively, in the three and six month periods ended June 30, 2006, compared to the same periods in 2005. On a year to date basis through June 30, 2006, the increase reflects higher retiree and employee benefit costs of $0.9 million, higher salaries and compensation expenses of $0.4 million and higher utility operating costs of $0.1 million, partially offset by lower audit and legal fees of $0.2 million and all other expenses, net of $0.1 million compared to 2005.

Depreciation and Amortization expense decreased $0.6 million and $1.5 million for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These decreases were primarily due to lower amortization on regulatory assets, partially offset by depreciation on normal utility plant additions. The Company's regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Interest Expense, Net increased by $0.2 million and $0.4 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The change in Interest Expense, Net was primarily driven by a higher weighted average cost of debt in 2006 compared to 2005.

Operating Revenues — Electric

Electric Operating Revenues – Total Electric Operating Revenues, increased by $7.3 million, or 15.8%, and by $17.0 million, or 18.3%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in the three month period reflects higher Purchased Electricity costs of $6.8 million and higher sales margin of $0.5 million. The net increase in Total Electric Operating Revenues in the six month period reflects higher Purchased Electricity costs of $17.4 million, offset by lower sales margin of $0.3 million and lower C&LM revenues of $0.1 million. As discussed above, the Company has recognized $1.7 million of revenues in the six months ended June 30, 2006 based on the temporary rate order, effective January 1, 2006.

Purchased Electricity and C&LM revenues increased a net $6.8 million, or 14.8%, and $17.4 million, or 18.8%, of Total Electric Operating Revenues in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity prices and lower spending on energy efficiency programs that were implemented during those periods. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin (Total Electric Operating Revenues less Cost of Electric Sales) was $14.4 million and $27.3 million in the three and six month periods ended June 30, 2006, respectively. This represents an increase of $0.5 million in the three month period and a decrease of $0.3 million in the six month period, compared to the same periods in 2005. The lower sales margin for the six months ended June 30, 2006, reflects decreases of $1.8 million related to lower SAS and other revenues and $0.2 million related to lower sales volume offset by the recognition of $1.7 million of revenue based on the Company's pending rate filing in New Hampshire, discussed above. The decrease in SAS revenues reflects the expiration in the fourth quarter of 2005 of the SAS tariff on Regulatory Assets, which is largely matched by a decrease in amortization expenses on Regulatory Assets (see discussion of Depreciation & Amortization below).

The following table details total Electric Operating Revenues and Sales Margin for the three and six month periods ended June 30, 2006 and 2005:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	2005	$ Change	% Change[1]	**2006**	2005	$ Change	% Change[1]
Electric Operating Revenue:								
Residential	**$ 23.3**	$ 18.5	$ 4.8	10.4%	**$ 47.6**	$ 39.5	$ 8.1	8.7%
Commercial / Industrial	**30.0**	27.5	2.5	5.4%	**62.2**	53.3	8.9	9.6%
Total Electric Operating Revenue	**$ 53.3**	$ 46.0	$ 7.3	15.8%	**$ 109.8**	$ 92.8	$ 17.0	18.3%
Cost of Electric Sales:								
Purchased Electricity	**$ 37.8**	$ 31.0	$ 6.8	14.8%	**$ 80.7**	$ 63.3	$ 17.4	18.8%
Conservation & Load Management	**1.1**	1.1	---	---	**1.8**	1.9	(0.1)	(0.1%)
Electric Sales Margin	**$ 14.4**	$ 13.9	$ 0.5	1.0%	**$ 27.3**	$ 27.6	$ (0.3)	(0.4%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Kilowatt-hour Sales - Unitil's total electric kWh sales were 0.3% and 0.8% lower in the three and six months ended June 30, 2006, respectively, compared with the same periods in 2005, reflecting customer growth offset by milder weather and a decline in average energy usage as customers appear to be reacting to higher energy prices by better managing their energy consumption. The weather in the Company's service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005, resulting in lower consumption of electricity for heating. In the second quarter of 2006 the weather in the Company's service territories was approximately 54% cooler than in the same period for 2005, resulting in lower consumption of electricity for cooling. Sales to residential customers increased 0.8% in the three month period as compared to the prior year period and decreased 0.7% in the six month period as compared to the prior year period. Sales to commercial and industrial (C&I) customers decreased 1.0% and 0.9% in the three and six month periods, respectively, as compared to the prior year periods.

The following table details total kWh sales for the three and six months ended June 30, 2006 and 2005 by major customer class:

kWh Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	2005	Change	% Change	**2006**	2005	Change	% Change
Residential	**149.7**	148.5	1.2	0.8%	**332.9**	335.3	(2.4)	(0.7%)
Commercial / Industrial	**262.8**	265.4	(2.6)	(1.0%)	**530.6**	535.4	(4.8)	(0.9%)
Total	**412.5**	413.9	(1.4)	(0.3%)	**863.5**	870.7	(7.2)	(0.8%)

Operating Revenues - Gas

Gas Operating Revenues – Total Gas Operating Revenues increased $1.3 million, or 26.0%, and $2.4 million, or 13.7%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in the three month period reflects higher Purchased Gas costs of $1.6 million, partially offset by lower sales margin of $0.3 million. The net increase in Total Gas Operating Revenues in the six month period reflects higher Purchased Gas costs of $3.3 million, offset by lower sales margin of $0.9 million.

Purchased Gas and C&LM revenues increased a net $1.6 million, or 32.0%, and $3.3 million, or 18.8%, of Total Gas Operating Revenues in the three and six month periods ended June 30, 2006, respectively, compared to the same period in 2005, reflecting higher gas commodity prices, higher unit sales and relatively flat spending on energy efficiency programs that were implemented during those periods. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin (Total Gas Operating Revenue less the Cost of Gas Sales) was $1.8 million and $5.2 million in the three and six month periods ended June 30, 2006, respectively. This represents decreases of $0.3 million, or 6.0%, and $0.9 million, or 5.1%, of Total Gas Operating Revenue in the three and six month periods compared to the same periods in 2005, respectively.

For the three month period, approximately $0.2 million of the decrease in gas sales margin is due to lower gas sales. Overall, gas sales were 28.9% higher in the second quarter of 2006 than in the same period of 2005, but this increase in gas sales is due to a new contract with a large industrial customer. Absent the sales from this new contract, gas sales were approximately 11.1% lower for the three month period ended June 30, 2006, compared to the same period in 2005. The Massachusetts Department of Telecommunications and Energy (MDTE) is in the process of approving the margin earned by the Company under the new contract, discussed above. Pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin. The remainder of the decrease in gas sales margin in the three month period is due to changes in the mix of customer billings period over period.

For the six month period, approximately $0.7 million of the decrease in gas sales margin is due to lower gas sales. Gas sales were 7.7% higher in the six months ended June 30, 2006 than in the same period of 2005. This increase in sales is due to the new transportation contract with a large industrial customer discussed above. Absent the sales from this new contract, gas sales were approximately 11.6% lower for the six months ended June 30, 2006 compared to the same period in 2005. The remainder of the decrease in gas sales margin in the six month period is due to changes in the mix of customer billings period over period.

The following table details total Gas Operating Revenues and Sales Margin for the three and six months ended June 30, 2006 and 2005:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	2005	$ Change	% Change[(1)]	**2006**	2005	$ Change	% Change[(1)]
Gas Operating Revenue:								
Residential	**$ 3.2**	$ 3.0	$ 0.2	4.0%	**$ 11.0**	$ 10.5	$ 0.5	2.8%
Commercial / Industrial	**2.1**	1.8	0.3	6.0%	**7.8**	7.0	0.8	4.6%
Total Firm Gas Revenue	**$ 5.3**	$ 4.8	$ 0.5	10.0%	**$ 18.8**	$ 17.5	$ 1.3	7.4%
Interruptible Gas Revenue	**1.0**	0.2	0.8	16.0%	**1.2**	0.1	1.1	6.3%
Total Gas Operating Revenue	**$ 6.3**	$ 5.0	$ 1.3	26.0%	**$ 20.0**	$ 17.6	$ 2.4	13.7%
Cost of Gas Sales:								
Purchased Gas	**$ 4.4**	$ 2.8	$ 1.6	32.0%	**$ 14.6**	$ 11.3	$ 3.3	18.8%
Conservation & Load Management	**0.1**	0.1	---	---	**0.2**	0.2	---	---
Gas Sales Margin	**$ 1.8**	$ 2.1	$ (0.3)	(6.0%)	**$ 5.2**	$ 6.1	$ (0.9)	(5.1%)

(1) Represents change as a percent of Total Gas Operating Revenue.

Therm Sales – Unitil's total gas sales increased 28.9% in the three months ended June 30, 2006 compared to the same period in 2005 and increased 7.7% in the six months ended June 30, 2006 compared to the same period in 2005. The increases in both of these periods were due to a new gas sales contract with a large industrial customer. Absent the sales from this new contract, sales to C&I customers were approximately 9.1% and 11.7% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Gas sales to residential customers were 13.0% and 11.5% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The declines in residential and C&I sales reflect lower average energy usage by customers during a period of higher energy prices and significantly milder winter weather in 2006. The weather in the Company's service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005, and the country as a whole experienced a record warm January.

The following table details total firm therm sales for the three and six months ended June 30, 2006 and 2005, by major customer class:

Therm Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	2005	Change	% Change	**2006**	2005	Change	% Change
Residential	**2.0**	2.3	(0.3)	(13.0%)	**6.9**	7.8	(0.9)	(11.5%)
Commercial / Industrial	**3.8**	2.2	1.6	72.7%	**9.8**	7.7	2.1	27.3%
Total	**5.8**	4.5	1.3	28.9%	**16.7**	15.5	1.2	7.7%

Operating Revenue - Other

Total Other Revenue increased $0.2 million, or 35.4%, and $0.2 million, or 25.8% in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These increases were the result of growth in revenues from the Company's unregulated energy brokering business, Usource.

The following table details total Other Revenue for the three and six months ended June 30, 2006 and 2005:

Other Revenue (000's)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	2005	$ Change	% Change	**2006**	2005	$ Change	% Change
Other	**$ 612**	$ 452	160	35.4%	**$ 1,199**	$ 953	$ 246	25.8%
Total Other Revenue	**$ 612**	$ 452	$ 160	35.4%	**$ 1,199**	$ 953	$ 246	25.8%

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $6.8 million, or 22.0%, and $17.4 million, or 27.5%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $1.5 million, or 54.2%, and $3.3 million, or 29.3%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These increases in Purchased Gas are attributable to increased therm sales and higher gas commodity costs. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) - O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expense increased $1.0 million and $1.1 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. For the six month period, the increase reflects higher retiree and employee benefit costs of $0.9 million, higher salaries and compensation expenses of $0.4 million and higher utility operating costs of $0.1 million, partially offset by lower audit and legal fees of $0.2 million and all other expenses, net of $0.1 million.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased less than $0.1 million, or 0.7%, and $0.1 million, or 4.0%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The decreases reflect the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense decreased $0.6 million, or 11.7% and $1.5 million, or 14.6%, for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These decreases were due to lower amortization on regulatory assets, partially offset by depreciation on normal utility plant additions. The Company's regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Local Property and Other Taxes - Local Property and Other Taxes increased by $0.1 million, or 5.9%, and $0.1 million, or 3.2%, for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The increase in the three month period was due to higher local property tax rates and higher payroll taxes. The increase in the six month period was due to higher payroll taxes.

Federal and State Income Taxes - Federal and State Income Taxes were lower by $0.1 million and $0.4 million in the three and six months ended June 30, 2006, respectively, compared to the same periods in 2005 reflecting lower pre-tax earnings.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (000's)	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Interest Expense				
Long-term Debt	$ **2,303**	$ 2,100	$ **4,622**	$ 4,202
Short-term Debt	**411**	225	**716**	441
Regulatory Liabilities	**67**	63	**109**	102
Subtotal Interest Expense	**2,781**	2,388	**5,447**	4,745
Interest Income				
Regulatory Assets	**(759)**	(637)	**(1,486)**	(1,225)
AFUDC and Other	**(56)**	(19)	**(82)**	(33)
Subtotal Interest Income	**(815)**	(656)	**(1,568)**	(1,258)
Total Interest Expense, Net	$ **1,966**	$ 1,732	$ **3,879**	$ 3,487

Interest Expense, Net increased by $0.2 million and $0.4 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Interest expense on long-term borrowings increased in both the three and six month periods in 2006 compared to 2005 due to the issuance of fixed rate long-term debt. In December 2005 Unitil's Massachusetts utility subsidiary, FG&E issued $15 million of unsecured long-term notes to institutional investors. Interest expense on short-term debt increased in both the three and six month periods in 2006 compared to 2005 primarily due to higher average short-term interest rates. These increases in interest expense were partially offset by an increase in interest income on regulatory assets primarily due to higher carrying charges on regulatory assets.

CAPITAL REQUIREMENTS

Cash provided by operating activities was $11.0 million during the first six months of 2006, a decrease of $2.8 million over the comparable period in 2005. Net Income was $0.8 million lower in the first half of 2006 compared to 2005. Depreciation and Amortization declined by $1.5 million in the six months ended June 30, 2006 as compared to the same period in 2005 reflecting a lower amortization on regulatory assets. The Deferred Tax Provision increased by $1.7 million during the first half of 2006 compared to the same period in 2005, reflecting a net change between current and deferred income taxes related to changes in Accrued Revenue balances. Cash sources from Accrued Revenue decreased by $3.9 million period over period due to higher energy costs, which will be collected from customers in future periods. Taxes Payable declined by $2.3 million, reflecting higher tax payments in 2006 compared to 2005. Cash uses for Accounts Payable decreased by $1.5 million compared to last year reflecting a higher level of funding of energy obligations in 2005. In addition, uses of cash for Deferred Restructuring Costs declined by $2.3 million in the first six months of 2006 compared to the same period last year. Deferred Restructuring Costs are regulatory assets that will be recovered from customers in future periods. All other changes in cash flows from operating activities were a net increase of $0.2 million in cash provided by operating activities.

Cash used in investing activities was $14.4 million for the six months ended June 30, 2006 an increase of $4.9 million over the comparable period in 2005. Annual capital expenditures are presently budgeted to be $33.4 million in 2006 compared to $24.4 million expended in 2005. These 2006 capital expenditures include approximately $6.6 million of cash outlays for the Automated Metering Infrastructure projects, which are expected to be completed in May 2007. Capital expenditure projections are subject to changes during the fiscal year.

Cash flows provided by financing activities were $4.1 million in the first six months of 2006. In the comparable period of 2005 cash used in financing activities amounted to $4.0 million, a net change between the two periods of $8.1 million. Cash provided for financing activities in the current period includes the proceeds from short-term bank borrowings of $8.0 million compared to the repayment of $0.2 million of short-term bank borrowings during the same period in 2005. The current period reflects the early repurchase of $0.2 million of preferred stock. Both periods reflect the payment of dividends to shareholders of approximately $3.9 million. During the first six months of 2006 and 2005, normal sinking fund payments amounted to approximately $0.2 million during both periods. Both periods include the proceeds of approximately $0.5 million received from the sale of Unitil Common Stock through the Dividend Reinvestment and Stock Purchase Plan and 401(k) plans. During the first half of 2005 the Company repaid capital lease obligations of $0.2 million.

Unitil’s subsidiary, UES expects to conclude a $15 million First Mortgage Bond issuance on or about September 30, 2006. This transaction is subject to the approval of the NHPUC and the final approval of UES’ Board of Directors. The proceeds from this financing will be used principally to reduce short-term debt, and for other corporate purposes. Accordingly, as discussed below, the Company reduced its unsecured credit lines by $4.0 million as of June 30, 2006.

At June 30, 2006, Unitil had completed the successful renewal of $40.0 million in unsecured revolving lines of credit through three banks. This represents a reduction from previously unsecured credit lines of $4.0 million. Average daily short-term borrowings during the first six months of 2006 were approximately $25.0 million, an increase of approximately $0.8 million over the comparable period in 2005. At June 30, 2006, the Company had available approximately $13.3 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $26.7 million. In addition, Unitil had $3.9 million in cash at June 30, 2006.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company’s policy is to limit these guarantees to two years or less. As of June 30, 2006, there are $8.0 million of guarantees outstanding and the longest term guarantee extends through May 31, 2008.

Critical Accounting Policies

The preparation of the Company’s financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company’s most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company’s significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company’s Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 22, 2006.

Regulatory Accounting - The Company’s principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, “Accounting for the Effects of Certain Types of Regulation.” (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company’s principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet. The Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In management's opinion, the Company's regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates approved by state and federal regulatory commissions. These regulated rates are applied to customers' accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

As discussed above, the Company's New Hampshire utility operating subsidiary, UES, filed a request for a base rate increase of $4.65 million with the New Hampshire Public Utilities Commission (NHPUC) which established temporary rate relief at current rate levels, effective January 1, 2006. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The rate filing is currently under review, with a NHPUC order anticipated before the end of 2006. Based on the temporary rate order and the current status of proceedings, management has recorded an estimate of expected revenue and expenses for the first six months of 2006.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Pension and Postretirement Benefit Obligations - The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with FASB Statement No. 87, "Employers' Accounting for Pensions" (SFAS No. 87) and FASB Statement No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" (SFAS No. 106). In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions.

The Company’s reported costs of providing pension and PBOP benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company’s health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and PBOP costs (collectively "postretirement costs") are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements. See Note 8.

Pension expense is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

Income Taxes - Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company’s actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under FASB Statement No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts.

Depreciation - Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company’s fixed assets.

Commitments and Contingencies - The Company’s accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, “Accounting for Contingencies” (SFAS No. 5). SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or loss that will ultimately be resolved when one or more future events occur or fail to occur.

Refer to “Recently Issued Accounting Pronouncements” in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company's debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company's short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company's interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company's short-term borrowings for the three months ended June 30, 2006 and June 30, 2005 were 5.46% and 3.51%, respectively. The average interest rates on the Company's short-term borrowings for the six months ended June 30, 2006 and June 30, 2005 were 5.24% and 3.27%, respectively.

MARKET RISK

Although Unitil's utility operating companies were subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of power and gas costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making which involves the pre-approval of the commodity prices included in rates. Additionally, as discussed below in Regulatory Matters, the Company has divested its long-term commodity-related contracts and therefore, has further reduced its exposure to commodity risk. In recent periods, the energy markets have experienced significant volatility, with unprecedented increases in energy prices. The Company is working with the regulatory commissions to address the issue of increasing energy prices and help the Company's customers work through this difficult period. The regulatory commissions in Massachusetts and New Hampshire have continued to approve full collection of these costs by Unitil's utility operating companies. However, the risk exists that the regulatory commissions would require the Company to finance, through deferrals, a portion of these costs for a period of time.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(000's except common shares and per share data)
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Operating Revenues				
Electric	**$ 53,328**	$ 46,034	**$ 109,758**	$ 92,846
Gas	**6,286**	4,953	**19,972**	17,640
Other	**612**	452	**1,199**	953
Total Operating Revenues	**60,226**	51,439	**130,929**	111,439
Operating Expenses				
Purchased Electricity	**37,781**	30,956	**80,693**	63,282
Purchased Gas	**4,378**	2,839	**14,564**	11,263
Operation and Maintenance	**7,061**	6,097	**13,153**	12,015
Conservation & Load Management	**1,190**	1,198	**1,987**	2,069
Depreciation and Amortization	**4,341**	4,915	**8,520**	9,981
Provisions for Taxes:				
Local Property and Other	**1,407**	1,328	**2,904**	2,814
Federal and State Income	**739**	795	**1,844**	2,200
Total Operating Expenses	**56,897**	48,128	**123,665**	103,624
Operating Income	**3,329**	3,311	**7,264**	7,815
Non-Operating Expenses (Income)	**(72)**	43	**(93)**	82
Income Before Interest Expense	**3,401**	3,268	**7,357**	7,733
Interest Expense, Net	**1,966**	1,732	**3,879**	3,487
Net Income	**1,435**	1,536	**3,478**	4,246
Less: Dividends on Preferred Stock	**34**	39	**64**	78
Earnings Applicable to Common Shareholders	**$ 1,401**	$ 1,497	**$ 3,414**	$ 4,168
Average Common Shares Outstanding - Basic	**5,592,616**	5,547,269	**5,584,935**	5,540,196
Average Common Shares Outstanding - Diluted	**5,606,609**	5,563,115	**5,599,108**	5,555,390
Earnings Per Common Share (Basic and Diluted)	**$ 0.25**	$ 0.27	**$ 0.61**	$ 0.75
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.035**	$ 1.035

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(000's)

	(UNAUDITED) June 30, 2006	June 30, 2005	December 31, 2005
ASSETS:			
Utility Plant:			
Electric	**$ 239,994**	$ 230,201	$ 234,153
Gas	**59,491**	54,237	58,675
Common	**25,826**	27,259	26,515
Construction Work in Progress	**11,735**	3,237	5,624
Total Utility Plant	**337,046**	314,934	324,967
Less: Accumulated Depreciation	**116,794**	108,807	111,646
Net Utility Plant	**220,252**	206,127	213,321
Current Assets:			
Cash	**3,854**	3,335	3,207
Accounts Receivable – Net of Allowance for Doubtful Accounts of $1,199, $501 and $550	**23,038**	18,050	23,551
Accrued Revenue	**8,706**	6,578	8,905
Refundable Taxes	**---**	---	351
Materials and Supplies	**3,490**	2,957	3,675
Prepayments	**1,901**	2,117	1,612
Total Current Assets	**40,989**	33,037	41,301
Noncurrent Assets:			
Regulatory Assets	**167,627**	186,544	179,719
Prepaid Pension Costs	**9,794**	9,932	11,099
Debt Issuance Costs	**2,343**	2,236	2,343
Other Noncurrent Assets	**3,429**	5,094	2,218
Total Noncurrent Assets	**183,193**	203,806	195,379
TOTAL	**$ 444,434**	$ 442,970	$ 450,001

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(000's)

	(UNAUDITED) June 30, 2006	June 30, 2005	December 31, 2005
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 94,582**	$ 93,377	$ 96,283
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**1,858**	2,102	2,102
Long-Term Debt, Less Current Portion	**125,199**	110,523	125,365
Total Capitalization	**221,864**	206,227	223,975
Current Liabilities:			
Long-Term Debt, Current Portion	**323**	296	308
Capitalized Leases, Current Portion	**278**	243	261
Accounts Payable	**19,705**	13,894	20,600
Short-Term Debt	**26,650**	25,490	18,700
Dividends Declared and Payable	**1,988**	1,975	50
Refundable Customer Deposits	**2,082**	1,757	2,031
Taxes Payable	**570**	2,284	---
Interest Payable	**1,353**	1,328	1,353
Other Current Liabilities	**2,137**	1,982	2,597
Total Current Liabilities	**55,086**	49,249	45,900
Deferred Income Taxes	**50,951**	52,596	52,297
Noncurrent Liabilities:			
Power Supply Contract Obligations	**102,245**	127,677	114,906
Capitalized Leases, Less Current Portion	**323**	109	324
Other Noncurrent Liabilities	**13,965**	7,112	12,599
Total Noncurrent Liabilities	**116,533**	134,898	127,829
TOTAL	**$ 444,434**	$ 442,970	$ 450,001

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(000's)
(UNAUDITED)

	Six Months Ended June 30,	
	2006	2005
Cash Flow from Operating Activities:		
Net Income	**$ 3,478**	$ 4,246
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**8,520**	9,981
Deferred Taxes	**(964)**	(2,653)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**513**	69
Accrued Revenue	**(743)**	3,176
Taxes Refundable / Payable	**921**	3,261
Materials and Supplies	**185**	123
Prepayments and Other	**(289)**	(346)
Accounts Payable	**(895)**	(2,355)
Refundable Customer Deposits	**51**	212
Other Current Liabilities	**(460)**	616
Deferred Restructuring and Other Charges	**(534)**	(2,805)
Other, net	**1,188**	224
Cash Provided by Operating Activities	**10,971**	13,749
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	**(14,438)**	(9,498)
Cash (Used in) Investing Activities	**(14,438)**	(9,498)
Cash Flows from Financing Activities:		
Proceeds from (Repayment) of Short-Term Debt, net	**7,950**	(185)
Repayment of Long-Term Debt	**(151)**	(141)
Dividends Paid	**(3,939)**	(3,913)
Issuance of Common Stock	**513**	546
Retirement of Preferred Stock	**(243)**	(11)
Repayment of Capital Lease Obligations	**(16)**	(244)
Cash Provided by (Used in) Financing Activities	**4,114**	(3,948)
Net Increase in Cash	**647**	303
Cash at Beginning of Period	**3,207**	3,032
Cash at End of Period	**$ 3,854**	$ 3,335
Supplemental Cash Flow Information:		
Interest Paid	**$ 5,358**	$ 4,685
Income Taxes Paid	**$ 1,893**	$ 1,693

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and six months ended June 30, 2006 are not necessarily indicative of results to be expected for the year ending December 31, 2006. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2005, as filed with the SEC on February 22, 2006, for a description of the Company's Basis of Presentation.

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES) (formed in 2002 by the combination and merger of Unitil's former utility subsidiaries Concord Electric Company and Exeter & Hampton Electric Company), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation clarified the accounting for uncertainty in income taxes recognized in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109). Specifically, FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. Additionally, FIN 48 provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods of income taxes, as well as the required disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company is in the process of completing its analysis of FIN 48 as it applies to the Company's operations and it does not expect that the adoption of FIN 48 will have a significant impact on the Company's Consolidated Financial Statements.

In March 2006, the FASB issued a Proposed Statement of Financial Accounting Standards (SFAS), "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." The Proposed SFAS would amend SFAS No. 87, SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106 and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." The Proposed SFAS would require companies to record on their balance sheets pension assets and liabilities, based on projected benefit obligations, and transition assets and obligations. Additionally, the Proposed SFAS would require companies to recognize in their statements of earnings actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of the Proposed SFAS is proposed to be December 15, 2006. The Company is currently assessing the impact the Proposed SFAS would have on the Company's results of operations and financial position.

In February 2006, the FASB issued FASB Statement No. 155, "Accounting for Certain Hybrid Financial Instruments", (SFAS No. 155), which amends FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities", (SFAS No.133) and FASB Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities", (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company has adopted SFAS No. 155 and it did not have an impact on the Company's Consolidated Financial Statements.

In February 2006, the FASB issued FASB Staff Position No. FAS 123(R)-4, (FSP 123(R)-4), "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement Upon the Occurrence of a Contingent Event". FSP 123(R)-4 addresses the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event and amends paragraphs 32 and A229 of revised FASB Statement No. 123(R), "Share-Based Payment", (SFAS No. 123(R)), which was issued in December 2004. SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. The Company uses the fair value method for share-based payment awards and therefore the provisions of SFAS No. 123(R) have no impact on the Consolidated Financial Statements. The Company has adopted the provisions of FSP 123(R)-4.

Reclassifications - Certain amounts previously reported have been reclassified to conform to current year presentation.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
06/22/06	08/15/06	08/01/06	$ 0.345
03/23/06	05/15/06	05/01/06	$ 0.345
01/12/06	02/15/06	02/01/06	$ 0.345
09/23/05	11/15/05	11/01/05	$ 0.345
06/17/05	08/15/05	08/01/05	$ 0.345
03/24/05	05/13/05	04/29/05	$ 0.345
01/13/05	02/15/05	02/01/05	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the second quarter of 2006, the Company sold 10,849 shares of its Common Stock, at an average price of $24.68 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $268,000 were used to reduce short-term borrowings.

During the second quarter of 2005, the Company sold 9,274 shares of its Common Stock, at an average price of $26.63 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $247,000 were used to reduce short-term borrowings.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 16, 2006, 14,375 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $366,563. On March 8, 2005, 10,900 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $299,423. On April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $293,715. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period.

Details on preferred stock at June 30, 2006, June 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) June 30,		December 31,
	2006	2005	2005
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 225**	$ 225	$ 225
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**874**	892	892
8.00% Series, $100 Par Value	**984**	1,210	1,210
Total Preferred Stock	**$ 2,083**	$ 2,327	$ 2,327

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at June 30, 2006, June 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) June 30, 2006	June 30, 2005	December 31, 2005
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**$ 15,000**	$ 15,000	$ 15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000	15,000
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19,000**	19,000	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000	14,000
6.79% Notes, Due October 15, 2025	**10,000**	10,000	10,000
5.90% Notes, Due December 15, 2030	**15,000**	---	15,000
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5,522**	5,819	5,673
Total	**125,522**	110,819	125,673
Less: Installments due within one year	**323**	296	308
Total Long-term Debt	**$ 125,199**	$ 110,523	$ 125,365

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at June 30, 2006 is estimated to be in a range of up to approximately $134 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, management believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of June 30, 2006 there are $8.0 million of guarantees outstanding and these guarantees extend through May 31, 2008. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and six months ended June 30, 2006 and June 30, 2005 (unaudited):

Three Months Ended June 30, 2006 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$ 53,328**	**$ 6,286**	**$ ---**	**$ 612**	**$ 60,226**
Segment Profit (Loss)	**1,794**	**(466)**	**134**	**(61)**	**1,401**
Identifiable Segment Assets	**322,837**	**100,656**	**19,722**	**1,219**	**444,434**
Capital Expenditures	**6,385**	**2,273**	**152**	**2**	**8,812**

Three Months Ended June 30, 2005 (000's)					
Revenues	$ 46,033	$ 4,953	$ 1	$ 452	$ 51,439
Segment Profit (Loss)	1,705	(357)	158	(9)	1,497
Identifiable Segment Assets	330,146	94,733	17,162	929	442,970
Capital Expenditures	3,251	1,791	12	---	5,054

Six Months Ended June 30, 2006 (000's)					
Revenues	**$109,758**	**$ 19,972**	**$ ---**	**$ 1,199**	**$ 130,929**
Segment Profit (Loss)	**3,056**	**261**	**259**	**(162)**	**3,414**
Identifiable Segment Assets	**322,837**	**100,656**	**19,722**	**1,219**	**444,434**
Capital Expenditures	**11,595**	**2,696**	**145**	**2**	**14,438**

Six Months Ended June 30, 2005 (000's)					
Revenues	$ 92,845	$ 17,640	$ 1	$ 953	$ 111,439
Segment Profit (Loss)	3,115	821	259	(27)	4,168
Identifiable Segment Assets	330,146	94,733	17,162	929	442,970
Capital Expenditures	7,276	2,195	27	---	9,498

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

Overview – Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil's utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the MDTE, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on an historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party vendors. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next five to seven years, is $140.3 million as of June 30, 2006 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E – Electric Division – FG&E's primary business is providing electric distribution service. Its current retail electric distribution rates were approved by the MDTE in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of June 30, 2006, approximately 53 percent of FG&E's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $37.9 million at June 30, 2006, and $35.9 million at June 30, 2005, and is expected to be recovered in FG&E's rates over the next five to seven years. In addition, as of June 30, 2006, FG&E had recorded on its balance sheets $54.0 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

Recovery of the deferred amounts described above will be made pursuant to a Settlement Agreement among FG&E, the Massachusetts Office of the Attorney General (Attorney General), and representatives of industrial and low-income customers. The Settlement Agreement, which was approved by the MDTE in 2005, provides for a rate path to allow recovery of FG&E's deferred stranded costs.

On March 7, 2006, the MDTE approved FG&E's 2003 and 2004 annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. FG&E's 2005 filing, which is subject to investigation, is pending. Management believes that this filing will be approved without material changes or adjustments.

FG&E – Gas Division – FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDTE in 2002. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

FG&E – Other – On October 27, 2004, the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism to provide for the recovery of costs associated with the Company's employee pension benefits and PBOP expenses. FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism provides for an annual filing and rate adjustment with the MDTE. As of June 30, 2006, FG&E has a regulatory asset of $2.9 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets.

On November 30, 2005, the MDTE announced a change in its method for recovery of gas cost-related bad debt, and determined that it would allow for full recovery of these costs on a reconciling basis. On December 15, 2005, FG&E filed a revised CGAC tariff reflecting this change which was approved effective January 1, 2006. FG&E also requested approval to recover its under-recovered gas cost-related bad debt for 2005 of approximately $164,000. On February 24, 2006, FG&E made a similar filing for its electric division, seeking approval to recover its actual electric supply-related bad debt through Default Service rates, effective January 1, 2006, and to recover its under-recovered electric supply-related bad debt for 2005 of approximately $84,000. On April 7, 2006, the MDTE consolidated the gas and electric requests for simultaneous review. A decision on these requests is expected in 2006. As of June 30, 2006, FG&E has regulatory assets for supply-related bad debt costs of $1.0 million.

UES – UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were established under a 2002 restructuring settlement agreement. On May 1, 2004, these distribution rates were increased by $1.0 million to provide for the recovery of PBOP costs. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES also provided a Transition Service supply for all rate classes through April 30, 2006. On May 1, 2006, customers previously on Transition Service were automatically placed on Default Service. Under a NHPUC approved settlement with the Office of the Consumer Advocate and the NHPUC Staff, UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of June 30, 2006, approximately 83 percent of UES' electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery and Transition and Default Service, including certain charges that are subject to annual or periodic reconciliation or future review. As of June 30, 2006, UES had recorded on its balance sheets $48.3 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately four years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 17, 2006, UES made its third annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2006, including reconciliation of prior year costs and revenues for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. The NHPUC approved the filing on April 28, 2006.

On December 11, 2004, UES filed with the NHPUC a Petition for an accounting order to defer certain pension costs above those included in its base rates, until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007 (also see Note 8 below). On April 7, 2005, the NHPUC issued an order denying UES' Petition for an accounting order. In its analysis denying UES' request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that the size and impact of increased pension expense is not clear and that a full examination of UES' income and expenses would be undertaken when UES files a rate case. As discussed below, the Company filed a full base rate case on November 4, 2005, which included a request for recovery of Pension/PBOP costs through a reconciling mechanism, the Pension/PBOP Adjustment Charge (PAC). As of June 30, 2006, UES has recorded deferred pension costs of $1.0 million.

On November 4, 2005, UES filed a request for a base rate increase of $4.65 million with the NHPUC. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving the request for temporary rates. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the pending base rate case. The Company cannot determine the ultimate outcome of this proceeding. Based on the temporary rate order and the current status of proceedings, management has recorded an estimate of expected revenue and expenses for the first six months of 2006. The estimate includes $1.7 million in estimated revenue and $1.0 million in estimated operating expenses and taxes, a net increase to operating income of $0.7 million. The impact of this estimated increase in operating income on previously reported first quarter results has been determined to be immaterial.

FERC – Wholesale Power Market Restructuring – FG&E, UES and Unitil Power are members of NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. The regional bulk power system is operated by an independent corporate entity, ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a RTO was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO effective February 1, 2005. Several parties have appealed various issues associated with the FERC's approval of the RTO to Federal District Court of Appeals. Those proceedings are ongoing.

On March 1, 2004, ISO-NE filed a proposal to implement LICAP in New England to allow for the imposition of incentive pricing for transmission constrained areas. UES and FG&E intervened in the proceeding. On April 11, 2006, a contested Settlement to resolve the LICAP proceeding was submitted by the FERC Settlement Judge to the FERC. It proposed transition payments for capacity until a Forward Capacity Market can be implemented, possibly by 2010. On June 16, 2006 the FERC approved the Settlement, for implementation December 1, 2006. This case is subject to a Request for Rehearing at FERC and may be subject to subsequent appeal to the Federal Courts.

The formation of an RTO, LICAP and other wholesale market changes, including changes to transmission rates, is not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy costs approved by the MDTE and NHPUC. It is likely, that retail rates will be significantly increased over the next several years as the Settlement is implemented.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of June 30, 2006, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site – The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan (MCP) that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed. FG&E is in the process of developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

On May 13, 2004 FG&E discovered an unauthorized excavation by another property owner on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated onto property owned by FG&E. FG&E promptly reported this discovery to the DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. The Completion Report for this release was submitted May 9, 2005.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1822 through 1978. In addition, on June 9, 2006, FG&E filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E’s total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Note 8: Pension and Postretirement Benefit Plans

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

Defined Benefit Pension Plan – The Company sponsors the Unitil Corporation Retirement Plan (the Plan), a defined benefit pension plan covering substantially all its employees. Under the Plan retirement benefits are based upon an employee’s level of compensation and length of service. The Company records annual expense and accounts for its defined benefit pension plan in accordance with SFAS No. 87.

In December 2003 and 2002, UES and FG&E filed requests with their respective state regulatory commissions for approval of accounting orders to mitigate certain accounting requirements related to pension plan assets which had been triggered by the substantial decline in the capital markets. UES and FG&E were granted approval of this regulatory accounting treatment in January 2003 and 2004. As a result of these approvals, the Company has recorded as a Regulatory Asset the amount of the Plan’s unfunded Accumulated Benefit Obligation (ABO) plus one dollar. These approvals allow UES and FG&E to treat their Additional Minimum Liability (AML) as Regulatory Assets under SFAS No. 71 and avoid the reduction in equity through other comprehensive income that would otherwise be required by SFAS No. 87.

On October 27, 2004 the MDTE approved FG&E’s request for a reconciliation rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF)) to recover the costs associated with the Company's pension and postretirement benefits other than pensions (PBOP), costs on an annually reconciling basis. As a result of this order, FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106 and amortizes increases and /or decreases in that deferral balance into the PAF for recovery over a three year period. The PAF provides for an annual filing and rate adjustment with the MDTE and requires that carrying charges on prepaid or (accrued) pension and PBOP assets and liabilities be collected from, or refunded to, utility customers. In 2005, FG&E received approval of its first annual filing and rate adjustment.

The Company initiated similar discussions for a reconciling rate mechanism for the pension costs of UES with the NHPUC. On December 11, 2004, UES filed with the NHPUC a Petition for an Accounting Order to defer certain pension costs above those included in its base rates until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007. On April 7, 2005, the NHPUC issued an order denying UES' Petition for an accounting order. In its analysis denying UES' request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that the size and impact of increased pension expense is not clear and that a full examination of UES' income and expenses would be undertaken when UES files a rate case. As discussed above, the Company filed a full base rate case on November 4, 2005, which included a request for recovery of Pension/PBOP costs through a reconciling mechanism, the PAC. UES' regulatory history with the NHPUC regarding this issue taken together with ratemaking precedent concerning pension cost recovery leads management to conclude that the pension costs are probable of recovery under SFAS No. 71. As of June 30, 2006, UES has recorded deferred pension costs of $1.0 million.

The following tables show the components of net periodic pension cost, (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Components of NPPC (000's)				
Service Cost	**$ 450**	$ 332	**$ 900**	$ 679
Interest Cost	**790**	792	**1,577**	1,548
Expected Return on Plan Assets	**(976)**	(837)	**(1,887)**	(1,702)
Amortization of Prior Service Cost	**27**	25	**53**	51
Amortization of Net (Gain) Loss	**306**	261	**662**	482
Subtotal NPPC	**597**	573	**1,305**	1,058
Net Amounts Capitalized and Deferred	**(68)**	(381)	**(644)**	(684)
NPPC Recognized	**$ 529**	$ 192	**$ 661**	$ 374

Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately ($164,000) and $143,000 for the three and six months ended June 30, 2006, respectively, recorded as increases (decreases) to Regulatory Assets on the Company's Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $209,000 and $366,000 for the three and six months ended June 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company's Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads. Included in the above pension expense amounts for 2006 are estimated expenditures to be recognized in the Company's rate proceeding in New Hampshire, as discussed above.

Key Assumptions (Weighted Average)	2006	2005
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50% (1)
Rate of Compensation Increase	**3.50%**	3.50%
Used to Determine NPPC:		
Discount Rate	**5.50%**	6.50% (1)
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%
Rate of Compensation Increase	**3.50%**	3.50%

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions – As of June 30, 2006, the Company has not yet made any contributions to the Plan for 2006. The Company is required to make a minimum contribution to its pension plan this year in the amount of $0.8 million. The Company contributed $2.5 million in 2005.

Postretirement Benefits - The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) primarily to provide health care and life insurance benefits to active employees. Prior to October 1, 2003, the Company funded certain postretirement benefits through the Unitil Retiree Trust (URT). URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. Effective January 1, 2004, the PBOP Plan was amended to provide certain healthcare and life insurance benefits, which were previously provided by the URT. The Company has established Voluntary Employee Benefit Trusts, into which it funds contributions to the PBOP Plan.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS No. 106-1) and Statement No. 106-2 (SFAS No. 106-2), "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary's annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS No. 106-1 and SFAS No. 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation and how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods. On January 28, 2005, the final Medicare Part D Prescription Drug Rules were posted to the Federal Register. Based on these rules, the Company's estimated PBOP Projected Benefit Obligation was reduced by $5.1 million. Also, the Company has estimated that its annual PBOP costs will be reduced by $0.4 million under the Act. These reductions are reflected in the Company's Consolidated Financial Statements. The Company's health care insurance provider has concluded that the Company's PBOP Plan is equal to or better than standard Medicare Part D coverage. Additionally, the Company's recognition of the Act is not expected to have any impact on the rate of participation in the PBOP Plan or per capita claims.

As discussed above, on October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis. On March 15, 2004 UES filed a petition with the NHPUC for recovery of PBOP costs. UES proposed an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004. The NHPUC approved this filing, effective May 1, 2004. As discussed above, on November 4, 2005, UES filed a request for a base rate increase of $4.65 million. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism. It is anticipated that the final determination of the amount and method of recovering UES' pension and PBOP costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding.

The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Components of NPPBC (000's)				
Service Cost	**$ 350**	$ 222	**$ 641**	$ 444
Interest Cost	**563**	456	**1,014**	912
Expected Return on Plan Assets	**(69)**	(15)	**(97)**	(30)
Amortization of Prior Service Cost	**340**	365	**680**	730
Amortization of Transition (Asset) Obligation	**5**	5	**11**	10
Amortization of Net (Gain) Loss	**80**	(16)	**80**	(32)
Subtotal NPPBC	**1,269**	1,017	**2,329**	2,034
Amounts Capitalized and Deferred	**(631)**	(474)	**(1,113)**	(948)
NPPBC Recognized	**$ 638**	$ 543	**$ 1,216**	$ 1,086

Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately $167,000 and $237,000 for the three and six months ended June 30, 2006, respectively, recorded as increases to Regulatory Assets on the Company's Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $139,000 and $278,000 for the three and six months ended June 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company's Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Weighted-Average Assumptions	**2006**	2005
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50% (1)
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	7.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013
Used to Determine NPPBC:		
Discount Rate	**5.50%**	6.50% (1)
Expected Long-Term Rate of Return on Plan Assets – Union	**8.50%**	8.50%
Expected Long-Term Rate of Return on Plan Assets – Non-Union	**5.50%**	5.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions – As of June 30, 2006, the Company has made $0.8 million of contributions to the PBOP Plan during 2006. The Company presently anticipates contributing an additional $1.8 million to fund the Plan in 2006 for an estimated total of $2.6 million. The Company contributed $2.5 million in 2005.

Supplemental Executive Retirement Plan - The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors.

The components of net periodic SERP cost are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Components of NPSC (000's)				
Service Cost	**$ 36**	$ 24	**$ 72**	$ 48
Interest Cost	**26**	20	**52**	40
Amortization of Transition Obligation	**4**	4	**8**	8
Amortization of Net Loss	**10**	1	**20**	2
Net Periodic SERP Cost	**$ 76**	$ 49	**$ 152**	$ 98

Employer Contributions – As of June 30, 2006, the Company has made payments of $36,000 to beneficiaries during 2006. The Company presently anticipates making additional benefit payments of $36,000 in 2006 for a total of $72,000.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2005 as filed with the Securities and Exchange Commission on February 22, 2006.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended June 30, 2006.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
4/1/06 – 4/30/06	---	---	---	n/a
5/1/06 – 5/31/06	168	$24.65	168	n/a
6/1/06 – 6/30/06	---	---	---	n/a
Total	168	$24.65	168	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated July 28, 2006 Announcing Earnings For the Quarter Ended June 30, 2006	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: July 28, 2006 /s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: July 28, 2006 /s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE CO MMON SHARE OUTSTANDING

(000's except for per share data)

(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
(000's, except per share data)	**2006**	2005	**2006**	2005
Net Income	**$1,435**	$1,536	**$3,478**	$4,246
Less: Dividend Requirements on Preferred Stock	**34**	39	**64**	78
Net Income Applicable to Common Stock	**$1,401**	$1,497	**$3,414**	$4,168
Weighted Average Number of Common Shares Outstanding – Basic	**5,592,616**	5,547,269	**5,584,935**	5,540,196
Dilutive Effect of Stock Options and Restricted Stock	**13,993**	15,846	**14,173**	15,194
Weighted Average Number of Common Shares Outstanding – Diluted	**5,606,609**	5,563,115	**5,599,108**	5,555,390
Earnings Per Share – Basic	**$0.25**	$0.27	**$0.61**	$0.75
Earnings Per Share – Diluted	**$0.25**	$0.27	**$0.61**	$0.75

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended September 30, 2006

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act.

Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X__

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 26, 2006
Common Stock, No par value	5,641,564 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended September 30, 2006

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

SAFE HARBOR CAUTIONARY STATEM ENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Unitil Corporation and subsidiaries' (Unitil or the Company) future operations, are forward-looking statements.

These statements include declarations regarding Management's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

? Variations in weather;
? Changes in the regulatory environment;
? Customers' preferences on energy sources;
? Interest rate fluctuation and credit market concerns;
? General economic conditions;
? Increased competition; and
? Fluctuations in supply, demand, transmission capacity and prices for energy commodities.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

Earnings Overview

The Company's Earnings Applicable to Common Shareholders was $1.8 million for the third quarter of 2006, an increase of $0.2 million compared to the same period in 2005. The improvement in earnings was primarily driven by the recent approval of new electric distribution base rates for Unitil Energy Systems, Inc. (UES), Unitil's New Hampshire electric utility subsidiary. Earnings per common share were $0.32 for the third quarter of 2006, an improvement of $0.04 per share compared with earnings of $0.28 per share for the third quarter of 2005.

For the nine month period ended September 30, 2006, earnings were $5.2 million compared to $5.7 million in 2005. Through the first nine months, earnings per share were $0.93 for 2006 compared with $1.03 per share for 2005. This decrease in earnings for the nine-month period reflects lower gas and electric sales primarily due to milder weather this year compared to 2005. The impact of the New Hampshire electric distribution base case is reflected in the Company's consolidated financial statements for both the three and nine month periods ending September 30, 2006.

On October 6, 2006, UES received approval from the New Hampshire Public Utilities Commission (NHPUC) of a settlement agreement, resolving all issues in its electric distribution base rate case filed in November 2005. Included in this Settlement Agreement is an increase in UES' electric base distribution rates of $2.3 million applied as of January 1, 2006; two future step increases to base rates totaling approximately $0.5 million related to utility plant additions in 2006; the recovery of $0.3 million of supply related costs through default service energy rates; a reduction of approximately $0.6 million in annual depreciation expense; and, the resolution of the recovery in rates of pension and other postretirement benefit costs and other operating costs.

Total electric kWh sales were 3.2% and 1.7% lower in the three and nine months ended September 30, 2006, respectively, reflecting milder weather and a decline in average energy usage per customer during the period of higher energy prices. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, resulting in lower consumption of electricity for heating related purposes. During the summer of 2006 the weather in the Company's service territories was approximately 11% cooler than in the same period for 2005, resulting in lower consumption of electricity for air conditioning purposes. Although the Company established a new record for peak electricity demand use by its customers in early August of 2006, the duration of very hot weather during this period was shorter than the extended period of very hot weather experienced during the summer of 2005. As a result, weather sensitive electric kWh sales in 2006 lagged behind same period sales in 2005.

Electric sales margin was lower in the three and nine month periods ended September 30, 2006, primarily reflecting a decrease in revenue related to the expiration of the Seabrook Amortization Surcharge (SAS) in late 2005. This decrease in SAS revenue is largely matched with a corresponding decrease in amortization expenses on Regulatory Assets, and therefore has no material impact on net income (see discussion on Depreciation and Amortization below). Absent the decrease in SAS revenues, electric sales margin increased $0.3 million and $2.2 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The higher sales margins in the three and nine months ended September 30, 2006, primarily reflect the Company's recently approved base rate increase in New Hampshire.

Total therm sales of natural gas increased 32.0% and 11.7% in the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005. The increases in both of these periods were due to a new gas sales contract with a large industrial customer. Absent the sales from this new special contract, total gas therm sales were approximately 5.6% and 9.8% lower for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The declines in sales, absent the sales from the new contract discussed above, reflect significantly milder winter weather in 2006 and lower average energy usage by customers during a period of higher energy prices. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, and the region as a whole experienced a record warm January.

Gas sales margin for the three month period ended September 30, 2006 was flat to the same period in 2005 and decreased $0.6 million in the nine month period ended September 30, 2006 compared to the same period in 2005. The decrease in gas margin is attributable to lower therm sales volume to customers as discussed above. Margin sharing under the special contract with a large industrial customer discussed above is currently pending approval from the MDTE. Accordingly, pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin.

Total Operation and Maintenance expenses decreased $0.2 million in the three month period ended September 30, 2006 compared to the same period in 2005. For the nine month period ended September 30, 2006, Operation and Maintenance expenses increased $1.3 million compared to the same period in 2005, reflecting higher retiree and employee benefit costs of $0.7 million, higher salaries and compensation expenses of $0.6 million and an increase in all other operating expenses of $0.2 million, net, partially offset by lower audit and legal fees of $0.2 million.

Depreciation and Amortization expense decreased $1.4 million and $2.9 million for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These decreases were due to lower utility plant depreciation rates resulting from the New Hampshire rate settlement and lower amortization on regulatory assets as a result of the expiration of the SAS, discussed above, partially offset by increased depreciation on normal utility plant additions.

Interest Expense, Net increased by $0.4 million and $0.7 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The change in Interest Expense, Net was primarily driven by a higher weighted average cost of debt in 2006 compared to 2005. Unitil's subsidiary, UES issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. The proceeds from this financing were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings.

Operating Revenues — Electric

Electric Operating Revenues – Total Electric Operating Revenues, increased by $8.6 million, or 16.4%, and by $25.5 million, or 17.5%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in the three month period reflects higher Purchased Electricity costs of $9.4 million, offset by lower sales margin of $0.8 million. The net increase in Total Electric Operating Revenues in the nine month period reflects higher Purchased Electricity costs of $26.6 million, offset by lower sales margin of $1.0 million and lower C&LM revenues of $0.1 million.

Purchased Electricity and C&LM revenues increased a net $9.4 million, or 17.9%, and $26.6 million, or 18.3%, of Total Electric Operating Revenues in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity prices and lower spending on energy efficiency programs that were implemented during those periods. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin was lower in the three and nine month periods ending September 30, 2006, primarily reflecting a decrease in revenue related to the expiration of the Seabrook Amortization Surcharge (SAS) in late 2005. This decrease in SAS revenue is largely matched with a corresponding decrease in amortization expenses on Regulatory Assets, and therefore has no material impact on net income (see discussion on Depreciation and Amortization below). Absent the decrease in SAS revenues, electric sales margin increased $0.3 million and $2.2 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The higher sales margins in the three and nine months ended September 30, 2006, primarily reflect the Company's recently approved base rate increase in New Hampshire.

The following table details total Electric Operating Revenues and Sales Margin for the three and nine month periods ended September 30, 2006 and 2005:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	$ Change	% Change(1)	**2006**	2005	$ Change	% Change(1)
Electric Operating Revenue:								
Residential	**$ 29.3**	$ 22.4	$ 6.9	13.1%	**$ 76.9**	$ 62.0	$ 14.9	10.2%
Commercial / Industrial	**31.9**	30.2	1.7	3.2%	**94.1**	83.5	10.6	7.3%
Total Electric Operating Revenue	**$ 61.2**	$ 52.6	$ 8.6	16.4%	**$ 171.0**	$ 145.5	$ 25.5	17.5%
Cost of Electric Sales:								
Purchased Electricity	**$ 46.4**	$ 37.0	$ 9.4	17.9%	**$ 126.9**	$ 100.3	$ 26.6	18.3%
Conservation & Load Management	**0.9**	0.9	---	---	**2.7**	2.8	(0.1)	(0.1%)
Electric Sales Margin	**$ 13.9**	$ 14.7	$ (0.8)	(1.5%)	**$ 41.4**	$ 42.4	$ (1.0)	(0.7%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Kilowatt-hour Sales - Unitil's total electric kWh sales were 3.2% and 1.7% lower in the three and nine months ended September 30, 2006, respectively, reflecting milder weather and a decline in average energy usage per customer during the period of higher energy prices. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, resulting in lower consumption of electricity for heating related purposes. During the summer of 2006 the weather in the Company's service territories was approximately 11% cooler than in the same period for 2005, resulting in lower consumption of electricity for air conditioning purposes. Although the Company established a new record for peak electricity demand use by its customers in early August of 2006, the duration of very hot weather during this period was shorter than the extended period of very hot weather experienced during the summer of 2005. As a result, weather sensitive electric kWh sales in 2006 lagged behind same period sales in 2005.

The following table details total kWh sales for the three and nine months ended September 30, 2006 and 2005 by major customer class:

kWh Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	% Change	**2006**	2005	Change	% Change
Residential	**188.6**	193.8	(5.2)	(2.7%)	**521.5**	529.0	(7.5)	(1.4%)
Commercial / Industrial	**294.9**	305.5	(10.6)	(3.5%)	**825.5**	840.9	(15.4)	(1.8%)
Total	**483.5**	499.3	(15.8)	(3.2%)	**1,347.0**	1,369.9	(22.9)	(1.7%)

Operating Revenues - Gas

Gas Operating Revenues – Total Gas Operating Revenues increased $0.9 million, or 25.7%, and $3.3 million, or 15.6%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in the three month period reflects higher Purchased Gas costs of $0.9 million. The net increase in Total Gas Operating Revenues in the nine month period reflects higher Purchased Gas costs of $3.9 million, offset by lower sales margin of $0.6 million.

Purchased Gas and C&LM revenues increased a net $0.9 million, or 25.7%, and $3.9 million, or 18.4%, of Total Gas Operating Revenues in the three and nine month periods ended September 30, 2006, respectively, compared to the same period in 2005, reflecting higher gas commodity prices, higher unit sales and relatively flat spending on energy efficiency programs that were implemented during those periods. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin for the three month period ended September 30, 2006 was flat to the same period in 2005 and decreased $0.6 million in the nine month period ended September 30, 2006 compared to the same period in 2005. The decrease in gas margin is attributable to lower therm sales volume to customers. Margin sharing under the special contract with a large industrial customer discussed above is currently pending approval from the MDTE. Accordingly, pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin.

The following table details total Gas Operating Revenues and Sales Margin for the three and nine months ended September 30, 2006 and 2005:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	$ Change	% Change(1)	**2006**	2005	$ Change	% Change(1)
Gas Operating Revenue:								
Residential	**$ 2.0**	$ 1.8	$ 0.2	5.7%	**$ 13.0**	$ 12.4	$ 0.6	2.8%
Commercial / Industrial	**1.4**	1.6	(0.2)	(5.7%)	**9.2**	8.6	0.6	2.8%
Total Firm Gas Revenue	**$ 3.4**	$ 3.4	$ ---	---	**$ 22.2**	$ 21.0	$ 1.2	5.6%
Interruptible Gas Revenue	**1.0**	0.1	0.9	25.7%	**2.2**	0.1	2.1	10.0%
Total Gas Operating Revenue	**$ 4.4**	$ 3.5	$ 0.9	25.7%	**$ 24.4**	$ 21.1	$ 3.3	15.6%
Cost of Gas Sales:								
Purchased Gas	**$ 2.8**	$ 1.9	$ 0.9	25.7%	**$ 17.1**	$ 13.2	$ 3.9	18.4%
Conservation & Load Management	**---**	---	---	---	**0.2**	0.2	---	---
Gas Sales Margin	**$ 1.6**	$ 1.6	$ ---	---	**$ 7.1**	$ 7.7	$ (0.6)	(2.8%)

(1) Represents change as a percent of Total Gas Operating Revenue.

Therm Sales – Unitil's total therm sales of natural gas increased 32.0% and 11.7% in the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005. The increases in both of these periods were due to a new gas sales contract with a large industrial customer. Absent the sales from this new contract, total sales were approximately 5.6% and 9.8% lower for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The declines in sales, absent the sales from the new contract discussed above, reflect significantly milder winter weather in 2006 and lower average energy usage by customers during a period of higher energy prices. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, and the region as a whole experienced a record warm January.

The following table details total firm therm sales for the three and nine months ended September 30, 2006 and 2005, by major customer class:

Therm Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	% Change	**2006**	2005	Change	% Change
Residential	**0.7**	0.7	---	---	**7.7**	8.6	(0.9)	(10.5%)
Commercial / Industrial	**2.6**	1.8	0.8	44.4%	**12.4**	9.4	3.0	31.9%
Total	**3.3**	2.5	0.8	32.0%	**20.1**	18.0	2.1	11.7%

Operating Revenue - Other

Total Other Revenue increased $0.2 million, or 28.7%, and $0.4 million, or 26.8% in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These increases were the result of growth in revenues from the Company's unregulated energy brokering business, Usource. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource. The Company will also realize future fees, estimated at the end of September, of $3.7 million from executed energy supply contracts running 2007 through 2011.

The following table details total Other Revenue for the three and nine months ended September 30, 2006 and 2005:

Other Revenue (000's)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	$ Change	% Change	**2006**	2005	$ Change	% Change
Other	**$ 678**	$ 527	151	28.7%	**$ 1,877**	$ 1,480	$ 397	26.8%
Total Other Revenue	**$ 678**	$ 527	$ 151	28.7%	**$ 1,877**	$ 1,480	$ 397	26.8%

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $9.4 million, or 25.5%, and $26.6 million, or 26.5%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $0.9 million, or 45.9%, and $4.0 million, or 30.2%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These increases in Purchased Gas are attributable to increased therm sales and higher gas commodity costs. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total Operation and Maintenance expenses decreased $0.2 million in the three month period ended September 30, 2006 compared to the same period in 2005. For the nine month period ended September 30, 2006, Operation and Maintenance expenses increased $1.3 million compared to the same period in 2005, reflecting higher retiree and employee benefit costs of $0.7 million, higher salaries and compensation expenses of $0.6 million and an increase in all other operating expenses of $0.2 million, net, partially offset by lower audit and legal fees of $0.2 million.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased less than $0.1 million, or 1.8%, and $0.1 million, or 3.3%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The decreases reflect the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense decreased $1.4 million, or 28.8%, and $2.9 million, or 19.3%, for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These decreases were primarily due to lower depreciation rates on utility plant resulting from the NHPUC's order in UES' base rate case, and lower amortization on regulatory assets, partially offset by depreciation on normal utility plant additions. The Company's regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Local Property and Other Taxes - Local Property and Other Taxes increased by less than $0.1 million, or 2.0%, and $0.1 million, or 3.0%, for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The increase in the three month period was principally due to higher local property tax rates. The increase in the nine month period was principally due to higher payroll taxes.

Federal and State Income Taxes - Federal and State Income Taxes were higher by $0.4 million in the three months ended September 30, 2006 compared to the same period in 2005 reflecting higher pre-tax earnings. Federal and State Income Taxes in the nine months ended September 30, 2006 were flat compared to the same period in 2005, reflecting a higher effective income tax rate in 2006 due to the expiration of book/tax differences related to the Seabrook regulatory asset discussed above.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's rate tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (000's)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Interest Expense				
Long-term Debt	$ **2,339**	$ 2,099	$ **6,962**	$ 6,301
Short-term Debt	**479**	282	**1,194**	723
Regulatory Liabilities	**80**	---	**189**	97
Subtotal Interest Expense	**2,898**	2,381	**8,345**	7,121
Interest Income				
Regulatory Assets	**(820)**	(755)	**(2,306)**	(1,975)
AFUDC and Other	**(131)**	(33)	**(213)**	(66)
Subtotal Interest Income	**(951)**	(788)	**(2,519)**	(2,041)
Total Interest Expense, Net	$ **1,947**	$ 1,593	$ **5,826**	$ 5,080

Interest Expense, Net increased by $0.4 million and $0.7 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. Interest expense on long-term borrowings increased in both the three and nine month periods in 2006 compared to 2005 due to the issuance of new fixed rate long-term debt. In December 2005 Unitil's Massachusetts utility subsidiary, FG&E issued $15 million of unsecured long-term notes to institutional investors. The notes have a term of 25 years and a coupon rate of 5.90%. Unitil's New Hampshire subsidiary, UES issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. The proceeds from these long-term financings were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. Interest expense on short-term debt increased in both the three and nine month periods in 2006 compared to 2005 primarily due to higher average short-term interest rates. These increases in interest expense were partially offset by an increase in interest income primarily due to higher carrying charges on regulatory assets.

Capital Requirements

Cash provided by operating activities was $17.1 million during the first nine months of 2006, a decrease of $3.9 million over the comparable period in 2005. Net Income was $0.5 million lower in the first nine months of 2006 compared to 2005. Depreciation and Amortization declined by $2.9 million in the three quarters ended September 30, 2006 as compared to the same period in 2005 reflecting the expiration of the Seabrook Amortization Surcharge in late 2005 (See Depreciation and Amortization above) and lower amortization on other regulatory assets, as well as, lower average book depreciation rates authorized for UES in its recently approved base rate case in New Hampshire. The Deferred Taxes provided an additional $1.5 million during the first nine months of 2006 as compared to the same period in 2005, reflecting a net change between current and deferred income taxes related principally to changes in the Accrued Revenue balances. Accounts Receivable provided $2.5 million over the current three quarters of 2006 and the comparable period in 2005. Cash sources from Accrued Revenue decreased by $6.3 million period over period due to higher energy costs and the recording of UES base rate relief for the January through September 2006 period, both of which will be collected from customers in future periods. Refundable Taxes declined by $1.1 million, reflecting higher tax payments in 2006 compared to 2005. Cash flow from Accounts Payable decreased by $1.4 million compared to last year reflecting a higher level of funding of energy costs and other operating expenses in 2006. In addition, cash used to fund Deferred Restructuring Costs declined by $5.3 million in the first nine months of 2006 as compared to the same period last year, reflecting a significant improvement in net cash inflows for the recovery of previously deferred costs related to industry restructuring. All other changes in cash flows from operating activities were a net decrease of $1.0 million in uses of cash in the nine months ended September 30, 2006 compared to the same period in 2005.

Cash used in investing activities was $24.7 million for the nine months ended September 30, 2006 an increase of $8.0 million over the comparable period in 2005. Annual capital expenditures are presently projected to be $33.5 million in 2006 compared to $24.4 million expended in fiscal 2005. These 2006 capital expenditures include approximately $6.7 million of cash outlays for the Automated Metering Infrastructure project, the first year of a two-year investment in the Company's metering infrastructure, expected to be completed in June 2007. Capital expenditure projections are subject to changes during the fiscal year.

Cash flows provided by financing activities were $8.1 million in the first nine months of 2006. In the comparable period of 2005 cash used in financing activities amounted to $3.8 million, a net change between the two periods of $11.9 million. Cash provided for financing activities in the current period included the issuance and sale of $15 million of First Mortgage Bonds, described below. Cash used in both periods reflect the payment of dividends to shareholders of approximately $5.9 million. Cash used for financing activities during the current period includes the repayment of $1.1 of short-term bank borrowings in 2006. The current period also reflects the repurchase of approximately $0.2 million of preferred stock. During the first nine months of 2006 and 2005, normal long-term note sinking fund payments amounted to approximately $0.2 million during both periods. Both the current and comparable prior last year included receipt of $0.8 million from the sale of Unitil Common Stock through the Dividend Reinvestment and Stock Purchase Plan and 401(k) plans. During the first nine months of 2006 and 2005, the Company repaid capital lease obligations of $0.1 million and $0.3, respectively.

Unitil's subsidiary, UES issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006 The proceeds from these long-term financings were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings.

At September 30, 2006 and December 31, 2005, Unitil had an aggregate of $40.0 million and $44.0 million, respectively, in unsecured revolving bank lines of credit through three banks. Unitil renews its lines of credit annually, and on June 30, 2006 at its annual renewal, Unitil reduced its lines of credit by $4 million due to lower projected borrowing requirements. Average daily short-term borrowings during the first nine months of 2006 were approximately $25.4 million, an increase of approximately $1.0 million over the comparable period in 2005. At September 30, 2006, the Company had available approximately $22.4 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $17.6 million. In addition, Unitil had $3.8 million in cash at September 30, 2006.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan’s liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company will be consulting with its actuary to assess the impact of these new funding rules, along with the other provisions of the PPA, on its pension plan.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company’s policy is to limit these guarantees to two years or less. As of September 30, 2006, there were $8.0 million of guarantees outstanding and the longest term guarantee extends through May 31, 2008.

Critical Accounting Policies

The preparation of the Company’s financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company’s most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company’s significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company’s Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 22, 2006.

***Regulatory Accounting* -** The Company’s principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the Federal Energy Regulatory Commission (FERC) and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, “Accounting for the Effects of Certain Types of Regulation.” (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company’s principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet. The Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In management's opinion, the Company's regulated operations will be subject to SFAS No. 71 for the foreseeable future.

***Utility Revenue Recognition* -** Regulated utility revenues are based on rates approved by state and federal regulatory commissions. These regulated rates are applied to customers' accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

***Allowance for Doubtful Accounts* -** The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

***Pension and Postretirement Benefit Obligations* -** The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with FASB Statement No. 87, "Employers' Accounting for Pensions" (SFAS No. 87) and FASB Statement No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" (SFAS No. 106). In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions.

In September 2006, the FASB issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination

Benefits," SFAS No. 106 and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets the overfunded or underfunded status of their pension and postretirement benefits other than pension plans. For pension plans, the benefit obligation will be measured using the projected benefit obligation while the accumulated benefit obligation will be used to measure the obligation for postretirement benefits other than pension. Additionally, SFAS No. 158 requires companies to recognize in their statements of earnings actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of SFAS No. 158 is December 15, 2006. The Company has a Defined Benefit Pension Plan and a Postretirement Benefits Other than Pension (PBOP) Plan (See Note 8). The Company expects that the implementation of SFAS No. 158 will have a significant impact on the recognition of pension and PBOP assets and liabilities on the Company's Balance Sheet and is currently assessing the recording of these items for the year ending December 31, 2006.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company will be consulting with its actuary to assess the impact of these new funding rules, along with the other provisions of the PPA, on its pension plan.

The Company's reported costs of providing pension and PBOP benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and PBOP costs (collectively "postretirement costs") are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements. See Note 8.

Pension expense is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

***Income Taxes* -** Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under FASB Statement No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts.

***Depreciation* -** Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. The depreciation rates ultimately determined from this process are approved by state regulators.

***Commitments and Contingencies* -** The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, "Accounting for Contingencies" (SFAS No. 5).

SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or loss that will ultimately be resolved when one or more future events occur or fail to occur.

Refer to “Recently Issued Accounting Pronouncements” in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company’s debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company’s short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company’s interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company’s short-term borrowings for the three months ended September 30, 2006 and September 30, 2005 were 5.82% and 4.01%, respectively. The average interest rates on the Company’s short-term borrowings for the nine months ended September 30, 2006 and September 30, 2005 were 5.44% and 3.51%, respectively.

MARKET RISK

Although Unitil's utility operating companies were subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of power and gas costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making which involves the pre-approval of the commodity prices included in rates. Additionally, as discussed below in Regulatory Matters, the Company has divested its long-term commodity-related contracts and therefore, has further reduced its exposure to commodity risk. In recent periods, the energy markets have experienced significant volatility, with unprecedented increases in energy prices. The Company is working with the regulatory commissions to address the issue of increasing energy prices and help the Company’s customers work through this difficult period. The regulatory commissions in Massachusetts and New Hampshire have continued to approve full collection of these costs by Unitil's utility operating companies. However, the risk exists that the regulatory commissions would require the Company to finance, through deferrals, a portion of these costs for a period of time.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTER S

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(000's except common shares and per share data)
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Operating Revenues				
Electric	**$ 61,200**	$ 52,642	**$ 170,958**	$ 145,488
Gas	**4,409**	3,485	**24,381**	21,125
Other	**678**	527	**1,877**	1,480
Total Operating Revenues	**66,287**	56,654	**197,216**	168,093
Operating Expenses				
Purchased Electricity	**46,430**	36,998	**126,909**	100,280
Purchased Gas	**2,780**	1,906	**17,142**	13,169
Operation and Maintenance	**6,558**	6,770	**20,127**	18,785
Conservation & Load Management	**915**	932	**2,902**	3,001
Depreciation and Amortization	**3,452**	4,846	**11,972**	14,827
Provisions for Taxes:				
Local Property and Other	**1,336**	1,314	**4,240**	4,128
Federal and State Income	**1,004**	648	**2,848**	2,848
Total Operating Expenses	**62,475**	53,414	**186,140**	157,038
Operating Income	**3,812**	3,240	**11,076**	11,055
Non-Operating Expenses (Income)	**38**	46	**(55)**	128
Income Before Interest Expense	**3,774**	3,194	**11,131**	10,927
Interest Expense, Net	**1,947**	1,593	**5,826**	5,080
Net Income	**1,827**	1,601	**5,305**	5,847
Less: Dividends on Preferred Stock	**35**	39	**99**	117
Earnings Applicable to Common Shareholders	**$ 1,792**	$ 1,562	**$ 5,206**	$ 5,730
Average Common Shares Outstanding - Basic	**5,605,208**	5,558,238	**5,591,692**	5,546,194
Average Common Shares Outstanding - Diluted	**5,619,082**	5,577,051	**5,605,765**	5,563,114
Earnings Per Common Share (Basic and Diluted)	**$ 0.32**	$ 0.28	**$ 0.93**	$ 1.03
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.38**	$ 1.38

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(000's)

	(UNAUDITED) September 30, 2006	September 30, 2005	December 31, 2005
ASSETS:			
Utility Plant:			
Electric	**$ 245,275**	$ 231,050	$ 234,153
Gas	**60,718**	54,906	58,675
Common	**25,292**	27,550	26,515
Construction Work in Progress	**14,557**	7,781	5,624
Total Utility Plant	**345,842**	321,287	324,967
Less: Accumulated Depreciation	**118,367**	111,654	111,646
Net Utility Plant	**227,475**	209,633	213,321
Current Assets:			
Cash	**3,821**	3,560	3,207
Accounts Receivable – Net of Allowance for Doubtful Accounts of $1,285, $561 and $550	**22,616**	19,648	23,551
Accrued Revenue	**9,599**	5,115	8,905
Refundable Taxes	**---**	---	351
Materials and Supplies	**4,229**	3,709	3,675
Prepayments	**1,193**	1,366	1,612
Total Current Assets	**41,458**	33,398	41,301
Noncurrent Assets:			
Regulatory Assets	**161,526**	180,045	179,719
Prepaid Pension Costs	**9,142**	9,197	11,099
Debt Issuance Costs	**2,560**	2,187	2,343
Other Noncurrent Assets	**2,379**	2,339	2,218
Total Noncurrent Assets	**175,607**	193,768	195,379
TOTAL	**$ 444,540**	$ 436,799	$ 450,001

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(000's)

	(UNAUDITED) September 30, 2006	(UNAUDITED) September 30, 2005	December 31, 2005
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 94,761**	$ 93,338	$ 96,283
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**1,858**	2,101	2,102
Long-Term Debt, Less Current Portion	**140,114**	110,445	125,365
Total Capitalization	**236,958**	206,109	223,975
Current Liabilities:			
Long-Term Debt, Current Portion	**329**	302	308
Capitalized Leases, Current Portion	**261**	169	261
Accounts Payable	**16,085**	13,167	20,600
Short-Term Debt	**17,575**	27,525	18,700
Dividends Declared and Payable	**1,991**	1,978	50
Refundable Customer Deposits	**2,182**	1,938	2,031
Taxes Payable	**1,235**	1,723	---
Interest Payable	**2,464**	2,195	1,353
Other Current Liabilities	**2,401**	2,314	2,597
Total Current Liabilities	**44,523**	51,311	45,900
Deferred Income Taxes	**50,540**	50,359	52,297
Noncurrent Liabilities:			
Power Supply Contract Obligations	**97,300**	121,291	114,906
Capitalized Leases, Less Current Portion	**252**	80	324
Other Noncurrent Liabilities	**14,967**	7,649	12,599
Total Noncurrent Liabilities	**112,519**	129,020	127,829
TOTAL	**$ 444,540**	$ 436,799	$ 450,001

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(000's)
(UNAUDITED)

	Nine Months Ended September 30,	
	2006	2005
Cash Flow from Operating Activities:		
Net Income	**$ 5,305**	$ 5,847
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**11,972**	14,827
Deferred Taxes	**(1,185)**	(2,642)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**935**	(1,529)
Accrued Revenue	**(1,648)**	4,639
Taxes Refundable / Payable	**1,586**	2,700
Materials and Supplies	**(554)**	(629)
Prepayments and Other	**419**	405
Accounts Payable	**(4,515)**	(3,082)
Refundable Customer Deposits	**151**	393
Interest Payable	**1,111**	867
Other Current Liabilities	**(196)**	948
Deferred Restructuring and Other Charges	**210**	(5,083)
Other, net	**3,552**	3,339
Cash Provided by Operating Activities	**17,143**	21,000
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	**(24,653)**	(16,680)
Cash (Used in) Investing Activities	**(24,653)**	(16,680)
Cash Flows from Financing Activities:		
Proceeds from (Repayment) of Short-Term Debt, net	**(1,125)**	1,850
Proceeds from Issuance of Long-Term Debt	**15,000**	---
Repayment of Long-Term Debt	**(230)**	(213)
Dividends Paid	**(5,916)**	(5,877)
Issuance of Common Stock	**757**	806
Retirement of Preferred Stock	**(244)**	(11)
Repayment of Capital Lease Obligations	**(118)**	(347)
Cash Provided by (Used in) Financing Activities	**8,124**	(3,792)
Net Increase in Cash	**614**	528
Cash at Beginning of Period	**3,207**	3,032
Cash at End of Period	**$ 3,821**	$ 3,560
Supplemental Cash Flow Information:		
Interest Paid	**$ 7,018**	$ 6,154
Income Taxes Paid	**$ 2,653**	$ 3,544

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

NOTE 1 – SUMMARY OF SIGNIFICA NT ACCOUNTING POLICI ES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and nine months ended September 30, 2006 are not necessarily indicative of results to be expected for the year ending December 31, 2006. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2005, as filed with the SEC on February 22, 2006, for a description of the Company's Basis of Presentation.

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES) (formed in 2002 by the combination and merger of Unitil's former utility subsidiaries Concord Electric Company and Exeter & Hampton Electric Company), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In September 2006, the FASB issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106 and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets the overfunded or underfunded status of their pension and postretirement benefits other than pension plans. For pension plans, the benefit obligation will be measured using the projected benefit obligation while the accumulated benefit obligation will be used to measure the obligation for postretirement benefits other than pension. Additionally, SFAS No. 158 requires companies to recognize in their statements of earnings actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of SFAS No. 158 is December 15, 2006. The Company has a Defined Benefit Pension Plan and a Postretirement Benefits Other than Pension (PBOP) Plan. The Company expects that the implementation of SFAS No. 158 will have a significant impact on the recognition of pension assets and liabilities on the Company's Balance Sheet and is currently assessing the impact of recording these items for the year ending December 31, 2006.

In September 2006, the FASB issued FASB Statement No. 157, "Fair Value Measurements", (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect SFAS No. 157 to have an impact on the Company's Consolidated Financial Statements.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation clarified the accounting for uncertainty in income taxes recognized in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109). Specifically, FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. Additionally, FIN 48 provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods of income taxes, as well as the required disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company is in the process of completing its analysis of FIN 48 as it applies to the Company's operations and it does not expect that the adoption of FIN 48 will have a significant impact on the Company's Consolidated Financial Statements.

In February 2006, the FASB issued FASB Statement No. 155, "Accounting for Certain Hybrid Financial Instruments", (SFAS No. 155), which amends FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities", (SFAS No.133) and FASB Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities", (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company does not expect SFAS No. 155 have an impact on the Company's Consolidated Financial Statements.

In February 2006, the FASB issued FASB Staff Position No. FAS 123(R)-4, (FSP 123(R)-4), "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement Upon the Occurrence of a Contingent Event". FSP 123(R)-4 addresses the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event and amends paragraphs 32 and A229 of revised FASB Statement No. 123(R), "Share-Based Payment", (SFAS No. 123(R)), which was issued in December 2004. SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. The Company uses the fair value method for share-based payment awards and therefore the provisions of SFAS No. 123(R) have no impact on the Consolidated Financial Statements. The Company has adopted the provisions of FSP 123(R)-4.

Reclassifications - Certain amounts previously reported have been reclassified to conform to current year presentation. Most significant has been the reclassification of certain expenses between Purchased Electricity, Purchased Gas and Operation and Maintenance expenses.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
09/29/06	11/15/06	11/01/06	$ 0.345
06/22/06	08/15/06	08/01/06	$ 0.345
03/23/06	05/15/06	05/01/06	$ 0.345
01/12/06	02/15/06	02/01/06	$ 0.345
09/23/05	11/15/05	11/01/05	$ 0.345
06/17/05	08/15/05	08/01/05	$ 0.345
03/24/05	05/13/05	04/29/05	$ 0.345
01/13/05	02/15/05	02/01/05	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first nine months of 2006, the Company sold 30,782 shares of its Common Stock, at an average price of $24.59 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $757,000 were used to reduce short-term borrowings.

During the first nine months of 2005, the Company sold 29,484 shares of its Common Stock, at an average price of $27.34 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $806,000 were used to reduce short-term borrowings.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 16, 2006, 14,375 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $366,563. On March 8, 2005, 10,900 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $299,423. On April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $293,715. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period.

Details on preferred stock at September 30, 2006, September 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) September 30,		December 31,
	2006	2005	2005
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 225**	$ 225	$ 225
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**874**	892	892
8.00% Series, $100 Par Value	**984**	1,210	1,210
Total Preferred Stock	**$ 2,083**	$ 2,327	$ 2,327

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at September 30, 2006, September 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) September 30, 2006	September 30, 2005	December 31, 2005
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**$ 15,000**	$ 15,000	$ 15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000	15,000
6.32% Series, Due September 15, 2036	**15,000**	---	---
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19,000**	19,000	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000	14,000
6.79% Notes, Due October 15, 2025	**10,000**	10,000	10,000
5.90% Notes, Due December 15, 2030	**15,000**	---	15,000
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5,443**	5,747	5,673
Total	**140,443**	110,747	125,673
Less: Installments due within one year	**329**	302	308
Total Long-term Debt	**$ 140,114**	$ 110,445	$ 125,365

On September 26, 2006 UES issued and sold $15 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement. The proceeds from this long-term financing were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. This issuance is reflected in the table above.

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at September 30, 2006 is estimated to be in a range of up to approximately $154 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, management believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2006 there are $8.0 million of guarantees outstanding and these guarantees extend through May 31, 2008. These guarantees are excluded from the recognition provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and nine months ended September 30, 2006 and September 30, 2005 (unaudited):

Three Months Ended September 30, 2006 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$ 61,200**	**$ 4,409**	**$ ---**	**$ 678**	**$ 66,287**
Segment Profit (Loss)	**2,438**	**(720)**	**103**	**(29)**	**1,792**
Identifiable Segment Assets	**323,502**	**99,972**	**19,941**	**1,125**	**444,540**
Capital Expenditures	**6,934**	**3,258**	**9**	**14**	**10,215**

Three Months Ended September 30, 2005 (000's)					
Revenues	$ 52,643	$ 3,485	$ (1)	$ 527	$ 56,654
Segment Profit (Loss)	2,040	(689)	226	(15)	1,562
Identifiable Segment Assets	322,324	95,050	18,352	1,073	436,799
Capital Expenditures	4,509	2,699	14	(40)	7,182

Nine Months Ended September 30, 2006 (000's)					
Revenues	**$170,958**	**$ 24,381**	**$ ---**	**$ 1,877**	**$ 197,216**
Segment Profit (Loss)	**5,494**	**(459)**	**362**	**(191)**	**5,206**
Identifiable Segment Assets	**323,502**	**99,972**	**19,941**	**1,125**	**444,540**
Capital Expenditures	**18,529**	**5,954**	**154**	**16**	**24,653**

Nine Months Ended September 30, 2005 (000's)					
Revenues	$145,488	$ 21,125	$ ---	$ 1,480	$ 168,093
Segment Profit (Loss)	5,545	(258)	485	(42)	5,730
Identifiable Segment Assets	322,324	95,050	18,352	1,073	436,799
Capital Expenditures	11,784	4,895	41	(40)	16,680

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

Overview – Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil's utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on an historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, all of Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party vendors. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next five to seven years, is $134.1 million as of September 30, 2006 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E – Electric Division – FG&E provides electric distribution service to customers under unbundled distribution rates approved by the MDTE. Its current retail electric distribution rates were approved by the MDTE in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of September 30, 2006, approximately 55 percent of FG&E's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $36.6 million at September 30, 2006, and $36.7 million at September 30, 2005, and is expected to be recovered in FG&E's rates over the next five to seven years. In addition, as of September 30, 2006, FG&E had recorded on its balance sheets $52.0 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

Recovery of the deferred amounts described above will be made pursuant to a Settlement Agreement among FG&E, the Massachusetts Office of the Attorney General (Attorney General), and representatives of industrial and low-income customers. The Settlement Agreement, which was approved by the MDTE in 2005, provides for a rate path to allow recovery of FG&E's deferred stranded costs.

On March 7, 2006, the MDTE approved FG&E's 2003 and 2004 annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. FG&E's 2005 filing, which is subject to investigation, is pending. Management expects that this filing will be approved without material changes or adjustments.

FG&E – Gas Division – FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDTE in 2002. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

FG&E – Other – On October 27, 2004, the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the Pension / PBOP Adjustment Factor (PAF), to provide for the recovery of costs associated with the Company's employee pension benefits and PBOP expenses. FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism provides for an annual filing and rate adjustment with the MDTE. As of September 30, 2006, FG&E has a regulatory asset of $3.1 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets.

On November 30, 2005, the MDTE announced a change in its method for recovery of gas cost-related bad debt, and determined that it would allow for full recovery of these costs on a reconciling basis. Following this change in policy, FG&E made filings with the MDTE seeking approval to recover its actual gas and electric supply-related bad debt through appropriate reconciling rate mechanisms consistent with the MDTE's ruling. On September 7, 2006, the MDTE issued an order allowing FG&E to recover its actual gas and electric supply-related bad debt effective December 1, 2005. Prior to this final approval, FG&E had recovered supply related bad debt based on a fixed rate formula that was resulting in a significant underrecovery of these costs. On September 27, 2006, the Attorney General filed a Petition for Appeal with the Massachusetts Supreme Judicial Court seeking to set aside the MDTE's order of September 7, 2006. FG&E intends to support the MDTE's order but management can not predict the outcome of the Attorney General's appeal at this time.

UES – UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were approved by the NHPUC in 2006 under the Settlement Agreement discussed above. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES also provided a Transition Service supply for all rate classes through April 30, 2006. On May 1, 2006, customers previously on Transition Service were automatically placed on Default Service. Under a NHPUC approved settlement with the Office of the Consumer Advocate and the NHPUC Staff, UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of September 30, 2006, approximately 82 percent of UES' electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery and Transition and Default Service, including certain charges that are subject to annual or periodic reconciliation or future review. As of September 30, 2006, UES had recorded on its balance sheets $45.3 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately four years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 17, 2006, UES made its third annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2006, including reconciliation of prior year costs and revenues for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. The NHPUC approved the filing on April 28, 2006.

On November 4, 2005, UES filed a request for a rate increase of $4.65 million with the NHPUC. The filing included a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and the inclusion of a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving the request for temporary rates to be effective January 1, 2006. On August 24, 2006 a settlement agreement resolving all base rate issues among UES, the Office of the Consumer Advocate, and the NHPUC Staff was filed, and on October 6, 2006, the agreement was approved by the NHPUC. The terms of the settlement agreement provide for an increase in base distribution rates of $2.3 million annually, effective as of January 1, 2006. Additionally, the approved settlement agreement authorizes two future step increases in base distribution rates, related to utility plant additions in 2006, of approximately $400,000 and $130,000 annually, effective as of November 1, 2006 and May 1, 2007, respectively. Also, the settlement agreement provides for the recovery of over $300,000 annually of supply-related operating and administrative costs through default energy service rates and a reduction of approximately $600,000 in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives. The stipulated rate of return under the settlement is 8.70%, including a return on equity of 9.67%. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates. Under the Settlement Agreement UES will amortize its deferred pension costs as these amortization costs are recovered over a six year period in base rates. UES had originally sought to recover pension and PBOP expenses in a reconciling mechanism similar to the PAF, described above. The approved settlement also authorizes a temporary rate surcharge for recovery of rate case expense and recoupment of the authorized distribution rate increase from January through October 2006.

FERC – Wholesale Power Market Restructuring – FG&E, UES and Unitil Power are members of NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. The regional bulk power system is operated by an independent corporate entity, ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a Regional Transmission Organization (RTO) was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO effective February 1, 2005. Several parties have appealed various issues associated with the FERC's approval of the RTO to Federal District Court of Appeals. Those proceedings are ongoing.

On March 1, 2004, ISO-NE filed a proposal to implement Locational Installed Capacity (LICAP) in New England to allow for the imposition of incentive pricing for transmission constrained areas. UES and FG&E intervened in the proceeding. On April 11, 2006, a contested Settlement to resolve the LICAP proceeding was submitted by the FERC Settlement Judge to the FERC. It proposed transition payments for capacity until a Forward Capacity Market can be implemented, possibly by 2010. On June 16, 2006 the FERC approved the Settlement, for implementation December 1, 2006. This case is subject to a Request for Rehearing at FERC and may be subject to subsequent appeal to the Federal Courts. The Company projects that that retail rates will be significantly increased over the next several years as the LICAP Settlement above is implemented.

The formation of an RTO, LICAP and other wholesale market changes, including changes to transmission rates, is not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy costs approved by the MDTE and NHPUC.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of September 30, 2006, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site – The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan (MCP) that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed. FG&E is in the process of developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1822 through 1978. In addition, on June 9, 2006, FG&E filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Note 8: Pension and Postretirement Benefit Plans

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

In September 2006, the FASB issued SFAS No. 158, an amendment of SFAS No. 87, SFAS No. 88, SFAS No. 106 and SFAS No. 132(R). SFAS No. 158 requires companies to record on their balance sheets the overfunded or underfunded status of their pension and postretirement benefits other than pension plans. For pension plans, the benefit obligation will be measured using the projected benefit obligation while the accumulated benefit obligation will be used to measure the obligation for postretirement benefits other than pension. Additionally, SFAS No. 158 requires companies to recognize in their statements of earnings actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of SFAS No. 158 is December 15, 2006. The Company has a Defined Benefit Pension Plan and a Postretirement Benefits Other than Pension (PBOP) Plan as discussed below. The Company expects that the implementation of SFAS No. 158 will have a significant impact on the recognition of pension and PBOP assets and liabilities on the Company's Balance Sheet and is currently assessing the impact of recording these items for the year ending December 31, 2006.

Defined Benefit Pension Plan – The Company sponsors the Unitil Corporation Retirement Plan (the Plan), a defined benefit pension plan covering substantially all its employees. Under the Plan retirement benefits are based upon an employee's level of compensation and length of service. The Company records annual expense and accounts for its defined benefit pension plan in accordance with SFAS No. 87.

In December 2003 and 2002, UES and FG&E filed requests with their respective state regulatory commissions for approval of accounting orders to mitigate certain accounting requirements related to pension plan assets which had been triggered by the substantial decline in the capital markets. UES and FG&E were granted approval of this regulatory accounting treatment in January 2003 and 2004. As a result of these approvals, the Company has recorded as a Regulatory Asset the amount of the Plan's unfunded Accumulated Benefit Obligation (ABO) plus one dollar. These approvals allow UES and FG&E to treat their Additional Minimum Liability (AML) as Regulatory Assets under SFAS No. 71 and avoid the reduction in equity through other comprehensive income that would otherwise be required by SFAS No. 87. With the implementation of SFAS No. 158 for the year ending December 31, 2006, as discussed above, this treatment under SFAS No. 71 will no longer apply.

On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF)) to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis. As a result of this order, FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106 and amortizes increases and /or decreases in that deferral balance into the PAF for recovery over a three year period. The PAF provides for an annual filing and rate adjustment with the MDTE and requires that carrying charges on prepaid or (accrued) pension and PBOP assets and liabilities be collected from, or refunded to, utility customers. In 2005, FG&E received approval of its first annual filing and rate adjustment.

As discussed above, on October 6, 2006, the NHPUC approved a Settlement Agreement, resolving all issues in UES' electric distribution base rate case filed in November 2005. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates. Under the Settlement Agreement UES will amortize its deferred pension costs as these amortization costs are recovered over a six year period in base rates. UES had originally sought to recover pension and PBOP expenses in a reconciling mechanism similar to the PAF, described above.

The following tables show the components of net periodic pension cost, (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Components of NPPC (000's)				
Service Cost	**$ 450**	$ 415	**$ 1,350**	$ 1,094
Interest Cost	**788**	765	**2,365**	2,314
Expected Return on Plan Assets	**(944)**	(851)	**(2,831)**	(2,553)
Amortization of Prior Service Cost	**27**	29	**80**	80
Amortization of Net Loss	**331**	377	**993**	859
Subtotal NPPC	**652**	735	**1,957**	1,794
Net Amounts Capitalized and Deferred	**(127)**	(366)	**(772)**	(1,050)
NPPC Recognized	**$ 525**	$ 369	**$ 1,185**	$ 744

Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately ($142,000) and $2,000 for the three and nine months ended September 30, 2006, respectively, recorded as increases (decreases) to Regulatory Assets on the Company's Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $3,000 and $369,000 for the three and nine months ended September 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company's Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Key Assumptions (Weighted Average)	**2006**	2005
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50% (1)
Rate of Compensation Increase	**3.50%**	3.50%
Used to Determine NPPC:		
Discount Rate	**5.50%**	6.50% (1)
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%
Rate of Compensation Increase	**3.50%**	3.50%

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions – As of September 30, 2006, the Company has not yet made any contributions to the Plan for 2006. The Company is required to make a minimum contribution to its pension plan this year in the amount of $2.5 million. The Company contributed $2.5 million in 2005. On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company will be consulting with its actuary to assess the impact of these new funding rules, along with the other provisions of the PPA, on its pension plan.

Postretirement Benefits - The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) primarily to provide health care and life insurance benefits to active employees. The Company has established Voluntary Employee Benefit Trusts, into which it funds contributions to the PBOP Plan.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS No. 106-1) and Statement No. 106-2 (SFAS No. 106-2), "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary's annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS No. 106-1 and SFAS No. 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation and how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods. On January 28, 2005, the final Medicare Part D Prescription Drug Rules were posted to the Federal Register. Based on these rules, the Company's estimated PBOP Projected Benefit Obligation was reduced by $5.1 million. Also, the Company has estimated that its annual PBOP costs will be reduced by $0.4 million under the Act. These reductions are reflected in the Company's Consolidated Financial Statements. The Company's health care insurance provider has concluded that the Company's PBOP Plan is equal to or better than standard Medicare Part D coverage. Additionally, the Company's recognition of the Act is not expected to have any impact on the rate of participation in the PBOP Plan or per capita claims.

As discussed above, on October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis. As discussed above, on October 6, 2006, the NHPUC approved a Settlement Agreement, resolving all issues in UES' electric distribution base rate case filed in November 2005. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates. UES had originally sought to recover pension and PBOP expenses in a reconciling mechanism similar to the PAF, described above.

The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Components of NPPBC (000's)				
Service Cost	**$ 321**	$ 300	**$ 962**	$ 745
Interest Cost	**507**	435	**1,522**	1,346
Expected Return on Plan Assets	**(49)**	(1)	**(146)**	(31)
Amortization of Prior Service Cost	**340**	322	**1,020**	1,051
Amortization of Transition (Asset) Obligation	**5**	5	**16**	16
Amortization of Net (Gain) Loss	**40**	33	**120**	---
Subtotal NPPBC	**1,164**	1,094	**3,494**	3,127
Amounts Capitalized and Deferred	**(559)**	(726)	**(1,673)**	(1,674)
NPPBC Recognized	**$ 605**	$ 368	**$ 1,821**	$ 1,453

Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately $119,000 and $357,000 for the three and nine months ended September 30, 2006, respectively, recorded as increases to Regulatory Assets on the Company's Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $196,000 and $474,000 for the three and nine months ended September 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company's Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Weighted-Average Assumptions	**2006**	2005
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50% (1)
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	7.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013
Used to Determine NPPBC:		
Discount Rate	**5.50%**	6.50% (1)
Expected Long-Term Rate of Return on Plan Assets – Union	**8.50%**	8.50%
Expected Long-Term Rate of Return on Plan Assets – Non-Union	**5.50%**	5.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions – As of September 30, 2006, the Company has made $1.1 million of contributions to the PBOP Plan during 2006. The Company presently anticipates contributing an additional $1.5 million to fund the Plan in 2006 for an estimated total of $2.6 million. The Company contributed $2.5 million in 2005.

Supplemental Executive Retirement Plan - The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors.

The components of net periodic SERP cost are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Components of NPSC (000's)				
Service Cost	**$ 36**	$ 24	**$ 110**	$ 71
Interest Cost	**26**	20	**78**	61
Amortization of Transition Obligation	**4**	4	**12**	13
Amortization of Net Loss	**10**	1	**29**	3
Net Periodic SERP Cost	**$ 76**	$ 49	**$ 229**	$ 148

Employer Contributions – As of September 30, 2006, the Company has made payments of $54,000 to beneficiaries during 2006. The Company presently anticipates making additional benefit payments of $18,000 in 2006 for a total of $72,000.

Note 9: Subsequent Event

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement, discussed above, resolving all issues in its electric distribution base rate case filed in November 2005. The key provisions of the Settlement Agreement approved by the Commission include:

? an increase in electric base distribution rates of $2,266,966 annually, effective as of January 2006;

? a stipulated overall rate of return of 8.70%, including a return on equity of 9.67%, applied to a proforma rate base of $96,046,267;

? two additional future step increases in electric base distribution rates, related to utility plant additions in 2006, of approximately $400,000 and $130,000 annually, effective as of November 1, 2006 and May 1, 2007, respectively;

? the recovery of over $300,000 annually of supply-related operating and administrative costs through default energy service rates;

? a reduction of approximately $600,000 in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives;

? the resolution of a multi-year effort by UES to recover in rates the rapidly escalating costs of pension and other postretirement benefit costs - the Settlement Agreement provides for the recovery of the costs sought by UES in the rate case as a component of base distribution rates;

? a comprehensive agreement on several rate design issues, including the allocation of the revenue increase to each customer class, the capping of the increase to low use residential customers and the maintenance of a discounted initial 250 kWh block for residential customers, and agreement on customer, volumetric and demand charges for each rate class;

? a provision for a temporary rate surcharge to provide for recovery of rate case expense and recoupment of the authorized distribution rate increase from January through October 2006.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the “Interest Rate Risk” and “Market Risk” sections of Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2005 as filed with the Securities and Exchange Commission on February 22, 2006.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended September 30, 2006.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
7/1/06 – 7/31/06	---	---	---	n/a
8/1/06 – 8/31/06	92	$24.77	92	n/a
9/1/06 – 9/30/06	---	---	---	n/a
Total	92	$24.77	92	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated October 26, 2006 Announcing Earnings For the Quarter Ended September 30, 2006	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: October 27, 2006

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: October 27, 2006

/s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING
(000's except for per share data)
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000's, except per share data)	**2006**	2005	**2006**	2005
Net Income	**$1,827**	$1,601	**$5,305**	$5,847
Less: Dividend Requirements on Preferred Stock	**35**	39	**99**	117
Net Income Applicable to Common Stock	**$1,792**	$1,562	**$5,206**	$5,730
Weighted Average Number of Common Shares Outstanding – Basic	**5,605,208**	5,558,238	**5,591,692**	5,546,194
Dilutive Effect of Stock Options and Restricted Stock	**13,874**	18,813	**14,073**	16,920
Weighted Average Number of Common Shares Outstanding – Diluted	**5,619,082**	5,577,051	**5,605,765**	5,563,114
Earnings Per Share – Basic	**$0.32**	$0.28	**$0.93**	$1.03
Earnings Per Share – Diluted	**$0.32**	$0.28	**$0.93**	$1.03

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 27, 2006

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 27, 2006

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 27, 2006

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	October 27, 2006
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	October 27, 2006
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	October 27, 2006

For Immediate Release

Exhibit 99.1

Contact: Mark Collin
Phone: 603-773-6612
Fax: 603-773-6812
Email: collin@unitil.com

Unitil Reports Third Quarter Earnings

Hampton, NH – October 26, 2006: Unitil Corporation (AMEX: UTL) (www.unitil.com) today announced earnings of $1.8 million for the third quarter of 2006, up $0.2 million compared to the third quarter of 2005. The improvement in earnings was primarily driven by the recent approval of new electric distribution base rates for Unitil Energy Systems, Inc. ("UES"), Unitil's New Hampshire electric utility subsidiary. Earnings per common share were $0.32 for the third quarter of 2006, an improvement of $0.04 per share compared with earnings of $0.28 per share for the third quarter of 2005.

The new distribution base rates for UES were approved by the New Hampshire Public Utilities Commission (the "Commission") on October 6, 2006. The Commission's rate order approved a comprehensive settlement agreement which provides for an increase in UES' base rates of $2.3 million to be applied as of January 1, 2006, together with other rate increases related to utility plant investments in 2006 and the recovery of energy supply-related administrative costs. In addition, the settlement agreement resolves the recovery in rates of employee and retiree pension and other post-retirement benefit costs and other utility operating expenses.

For the nine month period ended September 30, 2006, earnings were $5.2 million compared to $5.7 million in 2005. Through the first nine months, earnings per share were $0.93 for 2006 compared with $1.03 per share for 2005. This decrease in earnings reflects lower gas and electric sales primarily due to milder weather this year compared to the same nine-month period in 2005. The impacts of the New Hampshire electric distribution base rate case are reflected in the Company's consolidated financial statements for both the three and nine month periods ending September 30, 2006.

"We are pleased with our third quarter results which reflect the favorable financial impact of the Company's recently approved electric rate settlement in New Hampshire," said Robert G. Schoenberger, Unitil's Chairman, President and Chief Executive Officer. "We are also making good progress on other business initiatives, including implementation of a system-wide advanced metering system for both our gas and electric utility operations and the continued growth of our Usource energy brokering business."

Total electric sales in the three and nine months ended September 30, 2006 were down 3.2% and 1.7%, respectively, in the Company's utility service territories compared to the same periods in 2005. The declines in sales reflect significantly milder weather in both the winter heating season and summer cooling season and a continued trend toward lower average monthly energy usage by customers during a period of higher energy prices.

Total sales of natural gas increased 32.0% and 11.7% in the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005, primarily due to a new firm transportation contract with a large industrial customer. Absent the sales from this new contract, total gas sales were approximately 5.6% and 9.8% lower for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These lower gas sales also reflect the significantly milder winter weather in 2006 as well as the trend towards lower average monthly energy usage by customers during a period of higher energy prices. The weather in the Company's service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, and included a record warm January.

Total Operation and Maintenance expenses decreased $0.2 million in the three month period ended September 30, 2006 compared to the same period in 2005. For the nine month period ended September 30, 2006, Operation and Maintenance expenses increased $1.3 million compared to the same period in 2005, reflecting higher retiree and employee benefit costs of $0.7 million, higher salaries and compensation expenses of $0.6 million and an increase in all other operating expenses of $0.2 million, net, partially offset by lower audit and legal fees of $0.2 million.

Depreciation, Amortization, Taxes and Other expenses decreased $1.0 million and $2.7 million, respectively, in the three and nine month periods ended September 30, 2006 compared to 2005, due to lower utility plant depreciation rates resulting from the New Hampshire rate settlement and lower amortization on regulatory assets, partially offset by increased depreciation on normal utility plant additions.

Interest Expense, Net increased $0.4 million and $0.7 million in the three and nine month periods ended September 30, 2006, respectively, due to higher borrowings and interest rates compared to last year.

Usource, our unregulated energy brokerage business, recorded revenue of $1.9 million in the first nine months of 2006, an increase of more than 25% over the same period last year. Usource's revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource. The Company will also realize future fees estimated at the end of September 2006 of $3.7 million from executed energy supply term contracts running 2007 through 2011.

In the third quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

Unitil is a public utility holding company with subsidiaries providing electric service in New Hampshire and electric and gas service in Massachusetts and energy services throughout the Northeast. Its subsidiaries include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Unitil Power Corp., Unitil Realty Corp., Unitil Service Corp. and its unregulated business segment Unitil Resources, Inc. Usource L.L.C. is a subsidiary of Unitil Resources, Inc.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

The following table details total kilowatt-hour (kWh) sales of electricity for the three and nine months ended September 30, 2006 and 2005, by major customer class.

Electric kWh Sales (millions)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	% Change	**2006**	2005	% Change
Residential	**188.6**	193.8	(2.7%)	**521.5**	529.0	(1.4%)
Commercial/Industrial	**294.9**	305.5	(3.5%)	**825.5**	840.9	(1.8%)
Total	**483.5**	499.3	(3.2%)	**1,347.0**	1,369.9	(1.7%)

The following table details total firm therm sales of natural gas for the three and nine months ended September 30, 2006 and 2005, by major customer class.

Gas Firm Therm Sales (millions)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	% Change	**2006**	2005	% Change
Residential	**0.7**	0.7	---	**7.7**	8.6	(10.5%)
Commercial/Industrial	**2.6**	1.8	44.4%	**12.4**	9.4	31.9%
Total	**3.3**	2.5	32.0%	**20.1**	18.0	11.7%

Unitil Corporation

Selected Financial Information (Amounts In Thousands, except Shares and Per Share Data) (Unaudited)

Condensed Financial Data	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Operating Revenues	$ 66,287	$ 56,654	$ 197,216	$ 168,093
Purchased Electric and Gas and Conservation & Load Management	50,125	39,836	146,953	116,450
Operation & Maintenance	6,558	6,770	20,127	18,785
Depreciation, Amortization, Taxes & Other	5,792	6,808	19,060	21,803
Operating Income	3,812	3,240	11,076	11,055
Interest Expense, Net	1,947	1,593	5,826	5,080
Other (Income) Expense	38	46	(55)	128
Net Income	1,827	1,601	5,305	5,847
Preferred Dividends	35	39	99	117
Net Income Applicable to Common Stock	$ 1,792	$ 1,562	$ 5,206	$ 5,730

Earnings per Common Share				
Net Income Applicable to Common Stock	$ 0.32	$ 0.28	$ 0.93	$ 1.03
Average Common Shares Outstanding	5,619,082	5,577,051	5,605,765	5,563,114

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended March 31, 2007

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X__

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 26, 2007
Common Stock, No par value	5,669,951 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended March 31, 2007

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through two utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with an operating franchise in the southeastern seacoast and capital city areas of New Hampshire. FG&E is a combination gas and electric utility with an operating franchise in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 99,300 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are local "pipes and wires" utilities with a combined investment in net utility plant of $237.7 million at March 31, 2007. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

RATES AND REGULATION

Unitil's utility operations related to wholesale and interstate business activities are regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Public Utilities (MDPU), formerly the Massachusetts Department of Telecommunications and Energy, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets.

As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities provide for the delivery of that supply of electricity over their distribution systems at regulated rates. Both UES and FG&E continue to provide basic or default electric supply service to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without

limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

? Variations in weather;
? Changes in the regulatory environment;
? Customers' preferences on energy sources;
? Interest rate fluctuation and credit market concerns;
? General economic conditions;
? Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
? Increased competition; and
? Customers' future performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2006 as filed with the Securities and Exchange Commission on February 21, 2007.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal quarters ended March 31, 2007 and March 31, 2006 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 1 of this report.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $2.6 million for the first quarter of 2007, an increase of $0.6 million over Net Income for the first quarter of 2006. Earnings per common share (EPS) were $0.46 for the three months ended March 31, 2007, an improvement of $0.10 per share, or 28%, over the first quarter of 2006.

Unitil's improved first quarter earnings in 2007 over 2006 were driven by higher electric and gas base distribution rates and higher total gas sales. Unitil's non-regulated business, Usource, also realized higher revenues in 2007 which further contributed to the Company's overall improved earnings. These favorable factors were partially offset by higher operating expenses and higher interest expense in the current year.

The following table presents the significant items contributing to the improvement in earnings per share in the first quarter of 2007:

		Earnings Per Share
Three Months Ended March 31, 2006:	**$**	**0.36**
Electric Sales Margin		0.06
Gas Sales Margin		0.08
Usource Sales Margin		0.03
Operation & Maintenance Expense		(0.02)
Depreciation & Amortization		(0.03)
Interest Expense, net		(0.02)
Three Months Ended March 31, 2007:	**$**	**0.46**

In the first quarter of 2007, Unitil's electric kWh sales to residential customers increased 0.4% while sales to Commercial and Industrial (C&I) customers decreased 0.8% compared to the same period in 2006. Gas sales to residential customers remained level in the first quarter of 2007 compared to the same period in 2006 while sales to C&I customers were 15.0% higher in the current quarter, primarily due to a special contract with a large industrial customer.

Electric and Gas sales margin increased $0.6 million and $0.9 million, respectively, in the three months ended March 31, 2007 compared to the same period in 2006. Usource, our non-regulated energy brokering business, recorded increased sales margin of $0.3 million in the first quarter of 2007, an increase of 50% over the first quarter of 2006.

In the three months ended March 31, 2007 operating expenses increased by $1.0 million including higher Operation and Maintenance expenses of $0.2 million and higher Depreciation, Amortization, Taxes and Other increased $0.8 million. In the first three months of 2007, Interest Expense, Net, increased by $0.2 million compared to the same period in 2006, due to higher interest rates and higher average borrowings in 2007.

In 2006, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2007 and March, 2007 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three months ended March 31, 2007 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

Regulatory Assets increased $19.7 million as of March 31, 2007 compared to March 31, 2006, primarily reflecting the recording of Regulatory Assets for Retirement Benefit Obligations in accordance with newly issued Federal Accounting Standards Board (FASB) Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158) (See Note 8) and the recording of a Regulatory Asset for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts (See Note 7), partially offset by a decrease in Regulatory Assets related to current year cost recoveries.

Long-Term Debt increased $14.7 million as of March 31, 2007 compared to March 31, 2006, reflecting the issuance and sale on September 26, 2006 by UES of $15.0 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement.

Deferred Income Taxes decreased $16.9 million as of March 31, 2007 compared to March 31, 2006, primarily reflecting the recording of deferred tax assets related to Retirement Benefit Obligations, discussed below.

Retirement Benefit Obligations increased $39.1 million as of March 31, 2007 compared to March 31, 2006, primarily reflecting the recording of pension, PBOP and SERP obligations.

Environmental Obligations increased $12.0 million as of March 31, 2007 compared to March 31, 2006, reflecting the recording of a liability for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, discussed above.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – In the first quarter of 2007, Unitil's total electric kWh sales decreased 0.3% compared to the first quarter of 2006. Sales to residential customers increased 0.4% while sales to C&I customers decreased 0.8%.

The following table details total kWh sales for the three months ended March 31, 2007 and 2006 by major customer class:

kWh Sales (millions)

	Three Months Ended March 31,			
	2007	2006	Change	% Change
Residential	**184.0**	183.2	0.8	0.4%
Commercial/Industrial	**265.6**	267.8	(2.2)	(0.8%)
Total	**449.6**	451.0	(1.4)	(0.3%)

Electric Operating Revenues and Sales Margin - The following table details total Electric Operating Revenues and Sales Margin for the three months ended March 31, 2007 and 2006:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended March 31,			
	2007	2006	$ Change	% Change[1]
Electric Operating Revenue:				
Residential	**$ 31.5**	$ 24.2	$ 7.3	12.9%
Commercial / Industrial	**31.2**	32.2	(1.0)	(1.8%)
Total Electric Operating Revenue	**$ 62.7**	$ 56.4	$ 6.3	11.1%
Cost of Electric Sales:				
Purchased Electricity	**$ 48.2**	$ 42.8	$ 5.4	9.6%
Conservation & Load Management	**1.0**	0.7	0.3	0.5%
Electric Sales Margin	**$ 13.5**	$ 12.9	$ 0.6	1.2%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues increased by $6.3 million, or 11.1%, in the three months ended March 31, 2007 compared to the same period in 2006. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in the three months ended March 31, 2007 reflects higher Purchased Electricity costs of $5.4 million, higher C&LM revenues of $0.3 million and higher sales margin of $0.6 million.

Purchased Electricity and C&LM revenues increased a combined $5.7 million, or 10.1%, of Total Electric Operating Revenues in the three months ended March 31, 2007 compared to the same period in 2006, reflecting higher electric commodity prices. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased by $0.6 million in the three months ended March 31, 2007 compared to the same period in 2006, reflecting a rate increase in New Hampshire approved by regulators in fourth quarter of 2006 of $0.7 million, partially offset by the decline in sales units, $0.1 million.

Gas Sales, Revenues and Margin

Therm Sales – Therm sales of natural gas increased 8.3% in the three months ended March 31, 2007 compared to the same period in 2006. Sales to residential customers remained level in the first quarter of 2007 compared to the same period in 2006. Sales to C&I customers were 15.0% higher in the current quarter, primarily due to a new special contract with a large industrial customer.

The following table details total firm therm sales for the three months ended March 31, 2007 and 2006, by major customer class:

Therm Sales (millions)

	Three Months Ended March 31,			
	2007	2006	Change	% Change
Residential	**4.9**	4.9	---	---
Commercial/Industrial	**6.9**	6.0	0.9	15.0%
Total	**11.8**	10.9	0.9	8.3%

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three months ended March 31, 2007 and 2006:

Gas Operating Revenues and Sales Margin (millions)	Three Months Ended March 31,			
	2007	2006	$ Change	% Change[1]
Gas Operating Revenue:				
Residential	**$ 8.5**	$ 7.9	$ 0.6	4.4%
Commercial / Industrial	**5.7**	5.8	(0.1)	(0.7%)
Total Gas Operating Revenue	**$ 14.2**	$ 13.7	$ 0.5	3.7%
Cost of Gas Sales:				
Purchased Gas	**$ 9.8**	$ 10.1	$ (0.3)	(2.2%)
Conservation & Load Management	**---**	0.1	(0.1)	(0.7%)
Gas Sales Margin	**$ 4.4**	$ 3.5	$ 0.9	6.6%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $0.5 million, or 3.7%, in the three months ended March 31, 2007 compared to the same period in 2006. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in three months ended March 31, 2007 reflects higher sales margin of $0.9 million, offset by lower Purchased Gas costs of $0.3 million and lower C&LM revenues of $0.1 million.

Purchased Gas and C&LM revenues decreased a combined $0.4 million, or 2.9%, of Total Gas Operating Revenues in 2007 compared to 2006, primarily reflecting an increase in the amount of natural gas purchased by customers from third-party suppliers. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin increased $0.9 million in the three months ended March 31, 2007 compared to the same period in 2006 due to higher rates approved and implemented in early 2007and higher sales to large C&I customers, including sales to a large industrial customer under a special contract.

Operating Revenue - Other

The following table details total Other Revenue for the three months ended March 31, 2007 and 2006:

Other Revenue (Millions)	Three Months Ended March 31,			
	2007	2006	$ Change	% Change
Other	**$ 0.9**	$ 0.6	$ 0.3	50.0%
Total Other Revenue	**$ 0.9**	$ 0.6	$ 0.3	50.0%

Total Other Revenue increased $0.3 million, or 50.0%, in the three month period ended March 31, 2007 compared to the same period in 2006. The increase was the result of growth in revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $5.4 million, or 12.6%, in the three month period ended March 31, 2007 compared to the same period in 2006, reflecting higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $0.3 million, or 3.0%, in the three month period ended March 31, 2007 compared to the same period in 2006, reflecting an increase in the amount of natural gas purchased by customers from third-party suppliers. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) - O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expense increased $0.2 million in the three months ended March 31, 2007 compared to the same period in 2006. This increase was due to higher retiree and employee benefit costs of $0.3 million, driven by higher pension and post retirement benefit expenses, higher bad debt expenses of $0.1 million and higher salaries and compensation expenses of $0.1 million, partially offset by lower utility operating expenses of $0.1 million, lower outside services expenses of $0.1 million and all other operating expenses of $0.1 million, net.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use electricity and natural gas more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses increased by $0.2 million, or 25.0%, in three month period ended March 31, 2007 compared to the same period in 2006. The increase reflects the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense increased $0.3 million, or 7.1%, for the three month period ended March 31, 2007 compared to the same period in 2006. This increase was higher depreciation on normal utility plant additions.

Local Property and Other Taxes - Local Property and Other Taxes increased by less than $0.1 million, or 1.6% for the three month period ended March 31, 2007 compared to the same period in 2006. This increase was due to higher property tax rates.

Federal and State Income Taxes - Federal and State Income Taxes are higher by $0.4 million for the three months ended March 31, 2007 compared to the same period in 2006 reflecting higher pre-tax earnings.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (millions)	**Three Months Ended March 31,**		
	2007	2006	Change
Interest Expense			
Long-term Debt	**$ 2.6**	$ 2.3	$ 0.3
Short-term Debt	**0.4**	0.3	0.1
Regulatory Liabilities	**---**	---	---
Subtotal Interest Expense	**3.0**	2.6	0.4
Interest Income			
Regulatory Assets	**(0.8)**	(0.7)	(0.1)
AFUDC and Other	**(0.1)**	---	(0.1)
Subtotal Interest Income	**(0.9)**	(0.7)	(0.2)
Total Interest Expense, Net	**$ 2.1**	$ 1.9	$ 0.2

Interest Expense, Net increased by $0.2 million in the three month period ended March 31, 2007 compared to the same period in 2006. Interest expense on long-term borrowings increased due to the issuance of new fixed rate long-term debt. Unitil's New Hampshire subsidiary, UES, issued and sold $15 million of Series O 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. The proceeds from this long-term financing were used principally to finance utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. Interest expense on short-term debt increased in the three month period ended March 31, 2007 compared to the same period in 2006 due to higher short-term interest rates and higher levels of short-term borrowings. These increases in interest expense were partially offset by an increase in interest income due to higher earnings on funds used for capital projects and higher carrying charges earned on regulatory assets.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. At March 31, 2007 Unitil had an aggregate of $41.0 million in unsecured revolving bank lines of credit through three banks. Average daily short-term borrowings during the first three months of 2007 were approximately $26.2 million, an increase of approximately $2.7 million over the comparable period in 2006.

The maximum amount of short-term borrowings that may be incurred by Unitil and its subsidiaries has been subject to periodic regulatory oversight. At March 31, 2007, Unitil had regulatory authorization to incur total short-term bank borrowings up to a maximum of $55 million, and UES and FG&E had regulatory authorizations to borrow up to a maximum of $16 million and $35 million, respectively.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

On April 2007, Unitil agreed to privately place up to $20 million of long-term Notes, subject to market and other conditions, with institutional investors. The terms of the Notes will be determined between the Company and the purchasers of the Notes. The Notes are expected to have a maturity of up to 15 years and an interest rate of 6.33%. The Company intends to use the proceeds from the long-term financing to make capital contributions to its principal utility affiliates, UES and FG&E, to enable them to refinance existing short-term debt and for general corporate purposes of the Company and its subsidiaries.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2007, there were $10 million of guarantees outstanding and the longest term guarantee extends through March 13, 2009.

The tables below summarize the major sources and uses of cash (in millions) for the three months ended March 31, 2007 compared to the same period in 2006.

Cash Provided by Operating Activities	**$**	**6.1**	$	0.8

Cash Provided by Operating Activities - Cash Provided by Operating Activities was $6.1 million during the three months ended March 31, 2007, an increase of $5.3 million over the comparable period in 2006. Sources of cash from Net Income were $0.6 million higher in the first three months of 2007 compared to 2006. Sources of cash from Depreciation, Amortization and Deferred Taxes increased by $1.2 million in the current quarter compared to the same period in 2006. Working Capital related cash flows increased by $1.1 million during the first quarter of 2007 compared to the same period in 2006. All other changes in operating activities were a net $2.4 in sources of cash in the first three months of 2007 compared to 2006.

Cash (Used in) Investing Activities	**$**	**(9.6)**	$	(5.6)

Cash (Used in) Investing Activities - Cash (Used in) Investing Activities was $9.6 million for the three months ended March 31, 2007, an increase of $4.0 million over the comparable period in 2006. Annual capital expenditures are projected to be $32.4 million in 2007 compared to $33.6 million expended in fiscal 2006. These 2007 projected capital expenditures include approximately $5.5 million of cash outlays for the Automated Metering Infrastructure (AMI) project, the second year of a two-year investment in the Company's metering infrastructure. The Company's AMI expenditures were $2.8 during the first quarter of 2007 compared to $0.4 during the comparable period in 2006. Capital expenditure projections are subject to changes during the fiscal year.

Cash Provided by Financing Activities	**$ 1.7**	$ 3.8

Cash Provided by Financing Activities - Cash Provided by Financing Activities was $1.7 million in the three months ended March 31, 2007, a decrease of $2.1 million over the comparable period in 2006. Cash provided from financing activities from the proceeds of short-term bank borrowings was $2.3 million lower in the current period. All other cash flows provided from financing activities were a net $0.2 million higher in the first three months of 2007 compared to 2006.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 21, 2007.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet. Generally, the Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. Generally, the Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received.

Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior periods. Account write-offs and recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Retirement Benefit Obligations - The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements (See Note 8.)

Income Taxes - Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, “Accounting for Income Taxes” (SFAS No. 109) which is the authoritative pronouncement on accounting for and reporting income taxes.

In June 2006, the FASB issued Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48), an interpretation of FAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise’s financial statements. FIN 48 prescribes a “more-likely-than-not” recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition and classification. The Company adopted FIN 48 as of January 1, 2007, as required. The adoption of FIN 48 did not have a significant impact on the Company’s financial position and results of operations.

Depreciation - Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company’s fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies - The Company’s accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of March 31, 2007, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company’s consolidated financial statements below.

Refer to “Recently Issued Accounting Pronouncements’ in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company’s debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company’s short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company’s interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company’s short-term borrowings for the three months ended March 31, 2007 and March 31, 2006 were 5.77% and 5.00%, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions, except common shares and per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2007	2006
Operating Revenues		
Electric	**$ 62.7**	$ 56.4
Gas	**14.2**	13.7
Other	**0.9**	0.6
Total Operating Revenues	**77.8**	70.7
Operating Expenses		
Purchased Electricity	**48.2**	42.8
Purchased Gas	**9.8**	10.1
Operation and Maintenance	**6.5**	6.3
Conservation & Load Management	**1.0**	0.8
Depreciation and Amortization	**4.5**	4.2
Provisions for Taxes:		
Local Property and Other	**1.5**	1.4
Federal and State Income	**1.6**	1.2
Total Operating Expenses	**73.1**	66.8
Operating Income	**4.7**	3.9
Non-Operating (Income) Expenses	**---**	---
Income Before Interest Expense	**4.7**	3.9
Interest Expense, Net	**2.1**	1.9
Net Income	**2.6**	2.0
Less: Dividends on Preferred Stock	**---**	---
Earnings Applicable to Common Shareholders	**$ 2.6**	$ 2.0
Average Common Shares Outstanding – Basic (000's)	**5,627**	5,577
Average Common Shares Outstanding – Diluted (000's)	**5,644**	5,591
Earnings Per Common Share (Basic and Diluted)	**$ 0.46**	$ 0.36
Dividends Declared Per Share of Common Stock	**$ 0.69**	$ 0.69

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) March 31, 2007	March 31, 2006	December 31, 2006
ASSETS:			
Utility Plant:			
Electric	**$ 255.3**	$ 237.2	$ 250.3
Gas	**63.9**	59.0	63.5
Common	**25.3**	25.6	25.2
Construction Work in Progress	**17.2**	7.3	14.0
Total Utility Plant	**361.7**	329.1	353.0
Less: Accumulated Depreciation	**124.0**	113.8	121.2
Net Utility Plant	**237.7**	215.3	231.8
Current Assets:			
Cash	**2.8**	2.2	4.6
Accounts Receivable – Net of Allowance for Doubtful Accounts of $2.0, $1.0 and $1.7	**28.4**	26.5	22.5
Accrued Revenue	**12.0**	6.4	13.8
Materials and Supplies	**2.5**	2.6	4.5
Prepayments and Other	**1.1**	1.3	1.3
Total Current Assets	**46.8**	39.0	46.7
Noncurrent Assets:			
Regulatory Assets	**193.3**	173.6	198.8
Prepaid Pension	**---**	10.4	---
Debt Issuance Costs	**2.5**	2.4	2.6
Other Noncurrent Assets	**2.8**	3.2	3.5
Total Noncurrent Assets	**198.6**	189.6	204.9
TOTAL	**$ 483.1**	$ 443.9	$ 483.4

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) March 31, 2007	March 31, 2006	December 31, 2006
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 96.8**	$ 94.8	$ 97.8
Preferred Stock, Non-Redeemable, Non-Cumulative	**0.2**	0.2	0.2
Preferred Stock, Redeemable, Cumulative	**1.9**	1.9	1.9
Long-Term Debt, Less Current Portion	**140.0**	125.3	140.0
Total Capitalization	**238.9**	222.2	239.9
Current Liabilities:			
Long-Term Debt, Current Portion	**0.3**	0.3	0.3
Accounts Payable	**17.9**	14.7	19.8
Short-Term Debt	**29.7**	24.7	26.0
Taxes Payable	**2.1**	1.9	0.9
Interest and Dividends Payable	**4.5**	4.4	1.6
Other Current Liabilities	**4.1**	4.1	4.8
Total Current Liabilities	**58.6**	50.1	53.4
Deferred Income Taxes	**33.8**	50.7	34.5
Noncurrent Liabilities:			
Power Supply Contract Obligations	**87.6**	107.7	92.6
Retirement Benefit Obligations	**51.0**	11.9	49.7
Environmental Obligations	**12.0**	---	12.0
Other Noncurrent Liabilities	**1.2**	1.3	1.3
Total Noncurrent Liabilities	**151.8**	120.9	155.6
TOTAL	**$ 483.1**	$ 443.9	$ 483.4

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Three Months Ended March 31,	
	2007	2006
Operating Activities:		
Net Income	**$ 2.6**	$ 2.0
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**4.5**	4.2
Deferred Taxes	**(0.5)**	(1.4)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**(5.9)**	(2.9)
Accrued Revenue	**1.8**	1.6
Accounts Payable	**(1.9)**	(5.9)
Taxes Payable	**1.2**	2.3
All other Current Assets and Liabilities	**2.4**	1.4
Other, net	**1.9**	(0.5)
Cash Provided by Operating Activities	**6.1**	0.8
Investing Activities:		
Property, Plant and Equipment Additions	**(9.6)**	(5.6)
Cash (Used in) Investing Activities	**(9.6)**	(5.6)
Financing Activiti es:		
Proceeds from Short-Term Debt, net	**3.7**	6.0
Repayment of Long-Term Debt	**---**	(0.1)
Retirement of Preferred Stock	**---**	(0.2)
Dividends Paid	**(2.0)**	(2.0)
Issuance of Common Stock	**0.3**	0.2
Other, net	**(0.3)**	(0.1)
Cash Provided by Financing Activities	**1.7**	3.8
Net (Decrease) in Cash	**(1.8)**	(1.0)
Cash at Beginning of Period	**4.6**	3.2
Cash at End of Period	**$ 2.8**	$ 2.2
Supplemental Cash Flow Information:		
Interest Paid	**$ 2.0**	$ 1.5
Income Taxes Paid	**1.8**	0.8

(The accompanying notes are an integral part of these consolidated financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three months ended March 31, 2007 are not necessarily indicative of results to be expected for the year ending December 31, 2007. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2006, as filed with the SEC on February 21, 2007, for a description of the Company's Basis of Presentation.

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In February 2007, the FASB issued FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." (SFAS No. 159), effective for fiscal years beginning after November 15, 2007. SFAS No. 159 includes an amendment of FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities." SFAS No. 159 permits entities to choose, at specified election dates, to measure eligible items at fair value and requires unrealized gains and losses on items for which the fair value option has been elected to be reported in earnings. The Company does not expect SFAS No. 159 to have a material impact on the Company's Consolidated Financial Position.

In June 2006, the FASB issued Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48), an interpretation of FAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise’s financial statements. FIN 48 prescribes a “more-likely-than-not” recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition, and classification. The Company adopted FIN 48 as of January 1, 2007, as required. The adoption of FIN 48 did not have a significant impact on the Company’s financial position and results of operations. See Note 9.

In September 2006, the FASB issued FASB Statement No. 157, “Fair Value Measurements”, (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect SFAS No. 157 to have an impact on the Company’s Consolidated Financial Statements.

In February 2006, the FASB issued FASB Statement No. 155, “Accounting for Certain Hybrid Financial Instruments”, (SFAS No. 155), which amends SFAS No.133 and FASB Statement No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities”, (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity’s first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company’s adoption of SFAS No. 155 did not have an impact on the Company’s Consolidated Financial Statements.

Reclassifications - Certain amounts previously reported have been reclassified to conform to current year - presentation. The Company reclassified retirement benefit obligations from Other Noncurrent Liabilities to Retirement Benefit Obligations on the balance sheet for presentation purposes.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
03/22/07	05/15/07	05/01/07	$ 0.345
01/18/07	02/15/07	02/01/07	$ 0.345
09/29/06	11/15/06	11/01/06	$ 0.345
06/22/06	08/15/06	08/01/06	$ 0.345
03/23/06	05/15/06	05/01/06	$ 0.345
01/12/06	02/15/06	02/01/06	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first quarter of 2007, the Company sold 9,628 shares of its Common Stock, at an average price of $26.19 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $252,000 were used to fund capital expenditures.

During the first quarter of 2006, the Company sold 9,967 shares of its Common Stock, at an average price of $24.60 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $245,000 were used to fund capital expenditures.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company’s shareholders. On February 9, 2007, 9,020 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $230,461. Compensation expense associated with shares issued under the Plan is recognized on a monthly basis as the shares vest and was $0.1 million and $0.1

million for three months ended March 31, 2007 and 2006, respectively. At March 31, 2007, there was approximately $0.9 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 2.8 years as the shares vest.

Details on preferred stock at March 31, 2007, March 31, 2006 and December 31, 2006 are shown below:

(Amounts in Millions)

	(Unaudited) March 31,		December 31,
	2007	2006	2006
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.9**	0.9	0.9
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.1**	$ 2.1	$ 2.1

NOTE 4 – LONG-TERM DEBT

On April 16, 2007, Unitil Corporation agreed to privately place up to $20 million of long-term Notes, subject to market and other conditions, with institutional investors. The terms of the Notes will be determined by negotiations between the Company and the purchasers of the Notes. The Notes are expected to have a maturity of up to 15 years and an interest rate of 6.33%. The Company intends to use the proceeds from this long-term financing to make capital contributions to its principal affiliates, Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company, to enable them to refinance existing short-term debt and for general corporate purposes of the Company and its subsidiaries.

Details on long-term debt at March 31, 2007, March 31, 2006 and December 31, 2006 are shown below:

(Amounts in Millions)

	(Unaudited) March 31, 2007	**March 31, 2006**	December 31, 2006
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**$ 15.0**	$ 15.0	$ 15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	---	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5.3**	5.6	5.3
Total	**140.3**	125.6	140.3
Less: Installments due within one year	**0.3**	0.3	0.3
Total Long-term Debt	**$ 140.0**	$ 125.3	$ 140.0

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at March 31, 2007 is estimated to be in a range of up to approximately $156 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of March 31, 2007 there are $10 million of guarantees outstanding and these guarantees extend through March 13, 2009. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three months ended March 31, 2007 and March 31, 2006:

Three Months Ended March 31, 2007 (Millions)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$ 62.7**	**$ 14.2**	**$ ---**	**$ 0.9**	**$ 77.8**
Segment Profit	**1.4**	**1.1**	**0.1**	**---**	**2.6**
Identifiable Segment Assets	**347.1**	**114.0**	**20.9**	**1.1**	**483.1**
Capital Expenditures	**9.1**	**0.7**	**(0.2)**	**---**	**9.6**

Three Months Ended March 31, 2006 (Millions)					
Revenues	$ 56.4	$ 13.7	$ ---	$ 0.6	$ 70.7
Segment Profit (Loss)	1.3	0.7	0.1	(0.1)	2.0
Identifiable Segment Assets	319.2	101.9	21.5	1.3	443.9
Capital Expenditures	5.2	0.4	---	---	5.6

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2006 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 21, 2007.

Overview – Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on an historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, all of Unitil's customers have the opportunity to purchase their electric or natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the providers of basic or default service energy supply. UES and FG&E purchase electricity or natural gas for basic or default service from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the New Hampshire Public Utilities Commission (NHPUC) and Massachusetts Department of Public Utilities (MDPU) formerly the Massachusetts Department of Telecommunications and Energy, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next three to five years, is $120.8 million as of March 31, 2007 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E – Electric Division – FG&E provides electric distribution service to customers under unbundled distribution rates approved by the MDPU. Its current retail electric distribution rates were approved by the MDPU in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDPU. As of March 31, 2007, approximately 57 percent of FG&E's electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large commercial and industrial (C&I) customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers within FG&E's service area in Massachusetts has been a common experience throughout the New England electricity market.

As a result of the restructuring and the divestiture of FG&E's owned generation assets and buyout of FG&E's power supply obligations, Regulatory Assets on the Company's balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation's seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E's Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $33.1 million at March 31, 2007, and $35.1 million at March 31, 2006, and is expected to be recovered in FG&E's rates over the next three to five years. In addition, as of March 31, 2007, FG&E had recorded on its balance sheet $48.0 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil's consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

On December 1, 2006, FG&E submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. This filing and FG&E's 2005 filing are pending, subject to investigation. The Company expects that these filings will be approved without material changes or adjustments.

FG&E – Gas Division – FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDPU in 2007. FG&E's customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling Cost of Gas Adjustment Clause and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

On January 26, 2007, the MDPU approved a rate Settlement Agreement (Settlement) between FG&E and the Attorney General of Massachusetts for FG&E's Gas Division. Under the Settlement, FG&E will phase-in gas distribution rate changes with an initial rate increase of $1.2 million as of February 1, 2007, and an additional $1.0 million increase on November 1, 2007. The Settlement also includes agreement on several other rate matters and service quality performance measures for the company's Gas Division in the areas of safety, customer service and satisfaction.

On September 7, 2006, the MDPU issued an order allowing FG&E to recover the costs of its actual gas and electric supply-related bad debt effective December 1, 2005. Prior to this final approval, FG&E had recovered supply-related bad debt costs based on a fixed rate formula that produced a significant under-recovery of these costs. On September 27, 2006, the Attorney General filed a Petition for Appeal with the Massachusetts Supreme Judicial Court seeking to set aside the MDPU's order of September 7, 2006. FG&E intends to support the MDPU's order but the Company cannot predict the outcome of the Attorney General's appeal at this time.

UES – UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were approved by the NHPUC in 2006 under the Settlement Agreement discussed below. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES' costs for wholesale supply with no profit or markup. UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of March 31, 2007, approximately 79 percent of UES' electric load was served by Default Service. The remaining portion was served by competitive third party suppliers. The vast majority of customers being served by competitive third party suppliers are large C&I customers. Most residential and small commercial customers continue to purchase their electric supply through the retail distribution utilities. The concentration of the competitive retail market on higher use customers within UES' service area in New Hampshire has been a common experience throughout the New England electricity market.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery, including certain charges that remain subject to annual or periodic reconciliation or future review. As of March 31, 2007, UES had recorded on its balance sheets $39.6 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately three years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 16, 2007, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2007, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. The filing is pending, subject to investigation.

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement (Agreement) resolving its electric distribution base rate case filed in November, 2005. The terms of the Agreement provide for an increase in base distribution rates of $2.3 million annually, effective as of January 1, 2006. Additionally, the Agreement authorizes two step increases in base distribution rates, related to utility plant additions in 2006, of approximately $0.4 million and $0.1 million annually, effective as of November 1, 2006 and May 1, 2007, respectively. Also, the Agreement provides for the recovery of approximately $0.3 million annually of supply-related operating and administrative costs through default energy service rates and a reduction of approximately $0.6 million in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives. The stipulated rate of return under the settlement is 8.70%, including a return on equity of 9.67%. The Agreement also authorized a temporary rate surcharge for recovery of certain rate case expenses and recoupment of the authorized distribution rate increase from January through October 2006.

FERC – Wholesale Power Markets – FG&E, UES and Unitil Power, as well as virtually all New England electric utilities, are participants in ISO New England Inc., the RTO in New England. The regional bulk power system is operated by an independent corporate entity, ISO-NE. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economic manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England are performed on a regional basis. The ISO-NE Tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the cost recovery mechanisms for wholesale energy and transmission costs approved by the MDPU and NHPUC.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2006 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 21, 2007.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of March 31, 2007, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site – FG&E continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E has proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary closure of the site. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

FG&E has recovered the environmental response costs incurred at this former MGP site in gas rates pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover environmental response costs from gas customers over succeeding seven-year periods, without carrying costs. In addition FG&E has filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

FG&E is in the process of developing long range plans for a feasible permanent remediation solution for the Sawyer Passway site, including alternatives for re-use of the site. Included on the Company's Consolidated Balance Sheet at March 31, 2007 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of the site. A corresponding regulatory asset was recorded to reflect the future rate recovery for these costs. The amounts recorded do not assume any amounts are recoverable from insurance companies or other third parties.

The Company's ultimate liability for future environmental remediation costs may vary from estimates, which may be adjusted as new information or future developments become available. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit pension plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

In September 2006, the FASB issued SFAS No. 158 which requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

Pension Plan – The Company's defined benefit pension plan covers substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.

FG&E recovers the costs associated with its pension and PBOP costs on an annually reconciling basis through a rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF). FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and

SFAS No. 106 and amortizes increases and/or decreases in that deferral balance into the PAF for recovery over a three year period.

UES recovers its pension and PBOP expenses in base rates and amortizes deferred pension costs as these costs are recovered over a six year period in base rates.

The following tables show the components of net periodic pension cost, (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

	Three Months Ended March 31,			
		2007		2006
Components of NPPC (000's)				
Service Cost	**$**	**492**	$	450
Interest Cost		**834**		787
Expected Return on Plan Assets		**(1,047)**		(912)
Amortization of Prior Service Cost		**27**		27
Amortization of Net (Gain) Loss		**336**		355
Subtotal NPPC		**642**		707
Amounts Capitalized and Deferred		**(217)**		(577)
NPPC Recognized	**$**	**425**	$	130

Key Assumptions (Weighted Average)	**2007**	2006
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Used to Determine NPPC:		
Discount Rate	**5.50%**	5.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%
Rate of Compensation Increase	**3.50%**	3.50%

Employer Contributions – On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. As of March 31, 2007, the Company has not yet made any contributions to the Plan for 2007. The Company expects to contribute approximately $4.4 million to fund its pension plan in 2007. The Company contributed $2.5 million in 2006.

PBOP Plan - The Company sponsors the PBOP Plan, primarily to provide health care and life insurance benefits to employees and retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

As discussed above, on October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company's pension and PBOP costs on an annually reconciling basis. As discussed above, on October 6, 2006, the NHPUC approved a Settlement Agreement, resolving all issues in UES' electric distribution base rate case filed in November 2005. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates.

The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended March 31,	
	2007	2006
Components of NPPBC (000's)		
Service Cost	**$ 358**	$ 292
Interest Cost	**514**	450
Expected Return on Plan Assets	**(61)**	(28)
Amortization of Prior Service Cost	**340**	340
Amortization of Transition (Asset) Obligation	**5**	5
Amortization of Net (Gain) Loss	**17**	---
Subtotal NPPBC	**1,173**	1,059
Amounts Capitalized and Deferred	**(513)**	(482)
NPPBC Recognized	**$ 660**	$ 577

Weighted-Average Assumptions	**2007**	2006
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	5.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2016
Used to Determine NPPBC:		
Discount Rate	**5.50%**	5.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%/5.50%[(1)]**	8.50%/5.50% [(1)]
Health Care Cost Trend Rate Assumed for Next Year	**9.00%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2016

[(1)] Funding of the PBOP Plan is made into two VEBT's; one is a union VEBT and the other is a non-union VEBT. The expected long-term rate of return on plan assets for the union VEBT is 8.50%. The non-union VEBT is subject to income taxes and therefore the expected long-term rate of return on plan assets is 5.50%, reflecting the effect of taxes.

Employer Contributions – As of March 31, 2007, the Company has made $0.5 million of contributions to the PBOP Plan. The Company presently anticipates contributing an additional $1.7 million to fund the Plan in 2007 for an estimated total of $2.2 million. The Company contributed $2.2 million in 2006.

SERP - The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors.

The components of net periodic SERP cost are as follows:

	Three Months Ended March 31,			
		2007		2006
Components of NPPC (000's)				
Service Cost	**$**	**41**	$	36
Interest Cost		**29**		26
Amortization of Transition Obligation		**---**		4
Amortization of Net Loss		**11**		10
Net Periodic SERP Cost	**$**	**81**	$	76

Employer Contributions – As of March 31, 2007, the Company has made payments of $18,000 to beneficiaries. The Company presently anticipates making additional benefit payments of $54,000 in 2007 for a total of $72,000.

NOTE 9: INCOME TAXES

The Company evaluated its tax positions at December 31, 2006 and for the current interim reporting period ended March 31, 2007 in accordance with FIN 48, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2003; December 31, 2004; and December 31, 2005. Income tax filings for the year ended December 31, 2006 have been extended and are due September 15, 2007. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2006 as filed with the Securities and Exchange Commission on February 21, 2007.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended March 31, 2007.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
1/1/07 – 1/31/07	1,163 995	$25.463 $25.500	1,163 995	n/a n/a
2/1/07 – 2/28/07	---	---	---	n/a
3/1/07 – 3/31/07	289	$27.095	289	n/a
Total	2,447	$25.671	2,447	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated April 26, 2007 Announcing Earnings For the Quarter Ended March 31, 2007	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: April 27, 2007 /s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: April 27, 2007 /s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING
(Millions, except for per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2007	2006
Net Income	**$2.6**	$2.0
Less: Dividend Requirements on Preferred Stock	**---**	---
Net Income Applicable to Common Stock	**$2.6**	$2.0
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**5,626,553**	5,576,551
Dilutive Effect of Stock Options and Restricted Stock (000's)	**17,070**	14,353
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**5,643,623**	5,590,904
Earnings Per Share – Basic	**$0.46**	$0.36
Earnings Per Share – Diluted	**$0.46**	$0.36

UNITIL CORP (UTL)

10-Q

Quarterly report pursuant to sections 13 or 15(d)
Filed on 07/26/2007
Filed Period 06/30/2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For Quarter Ended June 30, 2007

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire *(State or other jurisdiction of incorporation or organization)*	**02-0381573** *(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire *(Address of principal executive office)*	**03842-1720** *(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 25, 2007
Common Stock, No par value	5,679,819 Shares

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended June 30, 2007

Table of Contents

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through two utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with an operating franchise in the southeastern seacoast and capital city areas of New Hampshire. FG&E is a combination gas and electric utility with an operating franchise in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 99,400 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are pure distribution utilities with a combined investment in net utility plant of $243.8 million at June 30, 2007. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

RATES AND REGULATION

Unitil's utility operations related to wholesale and interstate business activities are regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Public Utilities (MDPU), formerly the Massachusetts Department of Telecommunications and Energy, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets.

As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities provide for the delivery of that supply of electricity over their distribution systems at regulated rates. Both UES and FG&E continue to provide basic or default electric supply service to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' future performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2006 as filed with the Securities and Exchange Commission on February 21, 2007.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended June 30, 2007 and June 30, 2006 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 1 of this report.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $1.7 million for the second quarter of 2007, an increase of $0.3 million over the second quarter of 2006. Earnings per common share (EPS) were $0.30 for the three months ended June 30, 2007, an improvement of $0.05 per share, or 20%, over the second quarter of 2006. Unitil's improved second quarter performance was driven by higher gas sales and lower operation and maintenance expenses, which were partially offset by higher interest expense. For the six months ended June 30, EPS were $0.76 for 2007 compared to $0.61 for 2006, an improvement of $0.15, or 25%.

Unitil's non-regulated business, Usource, also continued to realize higher revenues compared to last year, which further contributed to the Company's overall improved earnings.

Table of Contents

The following table presents the significant items (discussed below) contributing to the improvement in earnings per share in the three and six month periods ended June 30, 2007:

2007 Earnings Per Share vs. 2006

	Period Ended June 30,	
	QTD	YTD
2006	**$ 0.25**	**$ 0.61**
Electric Sales Margin	(0.02)	0.04
Gas Sales Margin	0.06	0.14
Usource Sales Margin	0.03	0.06
Operation & Maintenance Expense	0.04	0.02
Depreciation, Amortization & Other	(0.02)	(0.05)
Interest Expense, Net	(0.04)	(0.06)
2007	**$ 0.30**	**$ 0.76**

Unitil's electric kWh sales to residential customers in the three and six month periods ended June 30, 2007 increased 1.5% and 0.9%, respectively, compared to the same periods in 2006 while sales to Commercial and Industrial (C&I) customers decreased 0.1% and 0.5% in those periods compared to the same periods in 2006. Gas sales to residential customers in the three and six month periods ended June 30, 2007 increased 15.0% and 4.3%, respectively, compared to the same periods in 2006 while sales to C&I customers increased 10.5% and 12.2% in those periods compared to the same periods in 2006.

Electric sales margin decreased $0.2 million and increased $0.5 million in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006. The lower electric sales margin in the second quarter of 2007 is due to the timing of recognition, in the second quarter of 2006, of revenues retroactive to January 1, 2006 associated with higher new electric rates established in the Company's electric rate case settlement in New Hampshire. The overall electric sales margin improvement through the first six months of 2007 compared to 2006 reflects additional step rate increases approved and implemented in the last half of 2006 and the first half of 2007.

Gas sales margin increased $0.5 million and $1.3 million in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006 reflecting higher gas sales due to more normal winter weather than last year and higher gas revenue from new higher rates approved and implemented in early 2007.

Usource, Unitil's non-regulated energy brokering business, recorded increased sales of $0.3 million and $0.6 million in the three and six month periods ended June 30, 2007 compared to the same periods of 2006, representing increases of 50% over the comparable 2006 periods.

Total Operation and Maintenance (O&M) expenses decreased $0.4 million and $0.2 in the three and six month periods ended June 30, 2007 compared to the same periods in 2006. The decrease in the six month period reflects lower outside services expenses of $0.3 million as well as cost efficiencies achieved in utility operating and all other expenses of $0.3 million, net, partially offset by higher salaries and compensation expenses of $0.3 million and higher retiree and employee benefit costs of $0.1 million.

Depreciation, Amortization, Taxes & Other, net expenses increased $0.3 million and $1.1 million in the three and six month periods ended June 30, 2007 compared to the same periods in 2006 primarily reflecting higher depreciation on utility plant additions and higher income taxes on higher levels of pre-tax earnings in 2007 compared to 2006.

Interest Expense, Net increased $0.4 million and $0.6 million in the three and six month periods ended June 30, 2007 compared to the same periods in 2006 reflecting an increase in the average cost of debt and higher long-term debt outstanding.

Table of Contents

In 2006, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2007, March, 2007 and June, 2007 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three and six months ended June 30, 2007 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

Regulatory Assets increased $19.7 million as of June 30, 2007 compared to June 30, 2006, reflecting the recording of Regulatory Assets for Retirement Benefit Obligations in accordance with newly issued Federal Accounting Standards Board (FASB) Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158) (See Note 8) and the recording of a Regulatory Asset for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts (See Note 7), partially offset by a decrease related to current year cost recoveries.

Long-Term Debt increased $34.8 million as of June 30, 2007 compared to June 30, 2006, reflecting the issuance and sale on September 26, 2006 by UES of $15.0 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement and the issuance and sale on May 2, 2007 by Unitil Corporation of $20 million of 6.33% long-term Notes, due May 1, 2022, to institutional investors, also in the form of a private placement.

Deferred Income Taxes decreased $19.1 million as of June 30, 2007 compared to June 30, 2006, primarily reflecting the recording of deferred tax assets related to Retirement Benefit Obligations, discussed below.

Retirement Benefit Obligations increased $38.4 million as of June 30, 2007 compared to June 30, 2006, primarily reflecting the recording of pension, PBOP and SERP obligations in accordance with SFAS No. 158, discussed above.

Environmental Obligations increased $12.0 million as of June 30, 2007 compared to June 30, 2006, reflecting the recording of a liability for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, discussed above.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Unitil's total electric kWh sales increased 0.5% and 0.1% in the three and six month periods ended June 30, 2007, respectively compared to the same periods in 2006. Electric kWh sales to residential customers in the three and six month periods ended June 30, 2007 increased 1.5% and 0.9%, respectively, compared to the same periods in 2006 while sales to C&I customers decreased 0.1% and 0.5% in those periods compared to the same periods in 2006.

The following table details total kWh sales for the three and six months ended June 30, 2007 and 2006 by major customer class:

kWh Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2007	**2006**	**Change**	**% Change**	**2007**	**2006**	**Change**	**% Change**
Residential	**152.0**	149.7	2.3	1.5%	**335.9**	332.9	3.0	0.9%
Commercial / Industrial	**262.5**	262.8	(0.3)	(0.1%)	**528.2**	530.6	(2.4)	(0.5%)
Total	**414.5**	412.5	2.0	0.5%	**864.1**	863.5	0.6	0.1%

[Table of Contents](#)

Electric Operating Revenues and Sales Margin – The following table details total Electric Operating Revenues and Sales Margin for the three and six month periods ended June 30, 2007 and 2006:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2007	**2006**	**$ Change**	**% Change(1)**	**2007**	**2006**	**$ Change**	**% Change(1)**
Electric Operating Revenue:								
Residential	**$ 24.7**	$ 23.3	$ 1.4	2.6%	**$ 56.2**	$ 47.6	$ 8.6	7.8%
Commercial / Industrial	**27.0**	30.1	(3.1)	(5.8%)	**58.2**	62.2	(4.0)	(3.6%)
Total Electric Operating Revenue	**$ 51.7**	$ 53.4	$ (1.7)	(3.2%)	**$ 114.4**	$ 109.8	$ 4.6	4.2%
Cost of Electric Sales:								
Purchased Electricity	**$ 36.3**	$ 37.7	$ (1.4)	(2.6%)	**$ 84.5**	$ 80.5	$ 4.0	3.6%
Conservation & Load Management	**1.0**	1.1	(0.1)	(0.2%)	**2.0**	1.9	0.1	0.1%
Electric Sales Margin	**$ 14.4**	$ 14.6	$ (0.2)	(0.4%)	**$ 27.9**	$ 27.4	$ 0.5	0.5%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues, decreased by $1.7 million, or 3.2%, and increased by $4.6 million, or 4.2%, in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net decrease in Total Electric Operating Revenues in the three month period reflects lower Purchased Electricity costs of $1.4 million, lower C&LM revenues of $0.1 million, and lower sales margin of $0.2 million. The net increase in Total Electric Operating Revenues in the six month period reflects higher Purchased Electricity costs of $4.0 million, higher C&LM revenues of $0.1 million and higher sales margin of $0.5 million.

Purchased Electricity and C&LM revenues decreased a net $1.5 million, or 2.8%, and increased a net $4.1 million, or 3.7%, of Total Electric Operating Revenues in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006. The decrease in the three month period primarily reflects an increase in the amount of electricity purchased by customers directly from third-party suppliers partially offset by higher electric commodity prices. The increase in the six month period primarily reflects higher electric commodity prices partially offset by an increase in the amount of electricity purchased by customers directly from third-party suppliers. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin decreased $0.2 million and increased $0.5 million in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006. The lower electric sales margin in the second quarter of 2007 is due to the timing of recognition, in the second quarter of 2006, of revenues retroactive to January 1, 2006 associated with higher new electric rates established in the Company's electric rate case settlement in New Hampshire. The overall electric sales margin improvement through the first six months of 2007 compared to 2006 reflects additional step rate increases approved and implemented in the last half of 2006 and the first half of 2007.

Table of Contents

Gas Sales, Revenues and Margin

Therm Sales – Unitil's total therm sales of natural gas increased 12.1% and 9.0% in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006. Gas sales to residential customers in the three and six month periods ended June 30, 2007 increased 15.0% and 4.3%, respectively, compared to the same periods in 2006 while sales to C&I customers increased 10.5% and 12.2% in those periods compared to the same periods in 2006, primarily due to a new special contract with a large industrial customer.

The following table details total firm therm sales for the three and six months ended June 30, 2007 and 2006, by major customer class:

Therm Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2007	2006	Change	% Change	2007	2006	Change	% Change
Residential	**2.3**	2.0	0.3	15.0%	**7.2**	6.9	0.3	4.3%
Commercial / Industrial	**4.2**	3.8	0.4	10.5%	**11.0**	9.8	1.2	12.2%
Total	**6.5**	5.8	0.7	12.1%	**18.2**	16.7	1.5	9.0%

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and six months ended June 30, 2007 and 2006:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2007	2006	$ Change	% Change(1)	2007	2006	$ Change	% Change(1)
Gas Operating Revenue:								
Residential	**$ 3.9**	$ 3.2	$ 0.7	11.1%	**$ 12.4**	$ 11.0	$ 1.4	7.0%
Commercial / Industrial	**2.5**	3.1	(0.6)	(9.5%)	**8.2**	9.0	(0.8)	(4.0%)
Total Gas Operating Revenue	**$ 6.4**	$ 6.3	$ 0.1	1.6%	**$ 20.6**	$ 20.0	$ 0.6	3.0%
Cost of Gas Sales:								
Purchased Gas	**$ 3.9**	$ 4.3	$ (0.4)	(6.3%)	**$ 13.7**	$ 14.4	$ (0.7)	(3.5%)
Conservation & Load Management	**0.1**	0.1	—	—	**0.1**	0.1	—	—
Gas Sales Margin	**$ 2.4**	$ 1.9	$ 0.5	7.9%	**$ 6.8**	$ 5.5	$ 1.3	6.5%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $0.1 million, or 1.6%, and $0.6 million, or 3.0%, in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in the three month period reflects higher sales margin of $0.5 million, offset by lower Purchased Gas costs of $0.4 million. The net increase in Total Gas Operating Revenues in the six month period reflects higher sales margin of $1.3 million, offset by lower Purchased Gas costs of $0.7 million.

[Table of Contents](#)

Purchased Gas and C&LM revenues decreased a net $0.4 million, or 6.3%, and $0.7 million, or 3.5%, of Total Gas Operating Revenues in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006, reflecting lower natural gas commodity prices and an increase in the amount of natural gas purchased by customers directly from third-party suppliers. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin increased $0.5 million and $1.3 million in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006 reflecting higher gas sales due to more normal winter weather than last year and higher gas revenue from new higher rates approved and implemented in early 2007.

Operating Revenue – Other

The following table details total Other Revenue for the three and six months ended June 30, 2007 and 2006:

Other Revenue (000's)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2007	2006	$ Change	% Change	2007	2006	$ Change	% Change
Other	**$ 0.9**	$ 0.6	$ 0.3	50.0%	**$ 1.8**	$ 1.2	$ 0.6	50.0%
Total Other Revenue	**$ 0.9**	$ 0.6	$ 0.3	50.0%	**$ 1.8**	$ 1.2	$ 0.6	50.0%

Total Other Revenue increased $0.3 million, or 50.0%, and $0.6 million, or 50.0% in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity decreased $1.4 million, or 3.7% and increased $4.0 million, or 5.0%, in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006. The decrease in the three month period reflects an increase in the amount of electricity purchased by customers directly from third-party suppliers partially offset by higher electric commodity prices. The increase in the six month period reflects higher electric commodity prices partially offset by an increase in the amount of electricity purchased by customers directly from third-party suppliers. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $0.4 million, or 9.3%, and $0.7 million, or 4.9%, in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006. These decreases in Purchased Gas are attributable to lower natural gas commodity prices and an increase in the amount of natural gas purchased by customers directly from third-party suppliers. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total Operation and Maintenance expenses decreased $0.4 million and $0.2 in the three and six month periods ended June 30, 2007 compared to the same periods in 2006. The decrease in the three month period reflects lower medical and other employee benefit costs, of $0.2 million, lower outside services expenses of $0.2 million, lower bad debt expenses of $0.1 million and all other operating expenses of $0.1 million, net, partially offset by higher salaries and compensation expenses of $0.2 million. The three month period ended June 30, 2006 included the recording of O&M costs related to the Company's electric base rate case settlement in New Hampshire and retroactive to January 1, 2006, as discussed above. The decrease in the six month period reflects lower outside services expenses of $0.3 million, lower utility operating expenses of $0.1 million and all other operating expenses of $0.2 million, net, partially offset by higher salaries and compensation expenses of $0.3 million and higher retiree and employee benefit costs of $0.1 million.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased $0.1 million, or 8.3%, and increased $0.1 million, or 5.0%, in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006. These changes reflect the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization – Depreciation and Amortization expense for the three month period ended June 30, 2007 was flat compared to the same period in 2006. For the six month period ended June 30, 2007, Depreciation and Amortization expense increased $0.3 million, or 3.5%, compared to the same period in 2006 primarily due to higher utility plant in service on which depreciation is recorded.

Local Property and Other Taxes – Local Property and Other Taxes decreased by less than $0.1 million, or 2.7% for the three month period ended June 30, 2007 compared to the same period in 2006 due primarily to lower payroll and property taxes. Local Property and Other Taxes for the six month period ended June 30, 2007 were flat compared to the same period in 2006 due primarily to lower payroll taxes offset by higher property tax rates.

Federal and State Income Taxes – Federal and State Income Taxes were higher by $0.2 million and $0.6 million in the three and six month periods ended June 30, 2007 compared to the same periods in 2006, respectively, reflecting higher pre-tax earnings.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) changed from income of $0.1 million in both the three and six month periods ended June 30, 2006 to expense of $0.1 million in both the three and six month periods ended June 30, 2007. These changes reflect the recognition in 2006 of a gain on the sale of land and timber harvest revenue.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's rate tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (Millions)	Three Months Ended June 30,			Six Months Ended June 30,		
	2007	2006	Change	2007	2006	Change
Interest Expense						
Long-term Debt	$ 2.8	$ 2.3	$ 0.5	$ 5.3	$ 4.6	$ 0.7
Short-term Debt	0.3	0.4	(0.1)	0.7	0.7	—
Regulatory Liabilities	0.2	0.1	0.1	0.3	0.2	0.1
Subtotal Interest Expense	3.3	2.8	0.5	6.3	5.5	0.8
Interest Income						
Regulatory Assets	(0.7)	(0.8)	0.1	(1.5)	(1.5)	—
AFUDC and Other	(0.2)	—	(0.2)	(0.3)	(0.1)	(0.2)
Subtotal Interest Income	(0.9)	(0.8)	(0.1)	(1.8)	(1.6)	(0.2)
Total Interest Expense, Net	$ 2.4	$ 2.0	$ 0.4	$ 4.5	$ 3.9	$ 0.6

Interest Expense, Net increased by $0.4 million and $0.6 million in the three and six month periods ended June 30, 2007, respectively, compared to the same periods in 2006 reflecting an increase in the average cost of debt and higher debt outstanding. Interest expense on long-term borrowings increased in both the three and six month periods in 2007 compared to 2006 due to the issuance of new fixed rate long-term debt. UES issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. The proceeds from this fixed rate long-term financing were used principally to finance utility plant additions that had been previously financed on an interim basis with variable rate short-term borrowings. On May 2, 2007, Unitil Corporation issued and sold $20 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors in the form of a private placement. The proceeds from this fixed rate long-term financing were used to refinance existing variable rate short-term debt and for general corporate purposes of the Company and its subsidiaries. Interest expense on short-term debt decreased $0.1 million in the three month period ended June 30, 2007 compared to the same period in 2006 primarily due to lower average short-term borrowings. For the six month period ended June 30, 2007, interest expense on short-term debt was flat to the same period in 2006. The increases in interest expense were partially offset by an increase in interest income.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. Long-term financings, mainly in the form of first mortgage bonds, unsecured notes and equity, are periodically issued to complement the addition of long-term plant investments and for other corporate purposes.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

On June 30, 2007 Unitil renewed $30 million in unsecured revolving lines of credit through three banks. Average daily short-term borrowings during the first six months of 2007 were approximately $20.8 million, a decrease of approximately $4.3 million over the comparable period in 2006, reflecting principally the receipt of the Unitil Note financing in May 2007, described below.

On May 2, 2007, Unitil completed the sale of $20 million of Senior Long-Term Notes, through a private placement to institutional investors. The Notes have a term of 15 years maturity and a coupon rate of 6.33%. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other general corporate purposes of the Company's principal utility subsidiaries.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to the duration of the contracts, which range from three months to three years. As of June 30, 2007, there were approximately $12.5 million of guarantees outstanding and the longest term guarantee extends through March 13, 2009.

The tables below summarize the major sources and uses of cash (in millions) for the six months ended June 30, 2007 compared to the same period in 2006.

Cash Provided by Operating Activities	**$ 17.0**	$ 11.0

Cash Provided by Operating Activities – Cash Provided by Operating Activities was $17.0 million during the first six months ended June 30, 2007, an increase of $6.0 million over the comparable period in 2006. Sources of cash from Net Income were $0.9 million higher in the first six months of 2007 compared to 2006. Sources of cash from Depreciation and Amortization increased by $0.3 million in the current period compared to the same period in 2006. An additional $1.3 million of cash was utilized for Deferred Taxes as compared to the comparable period in 2006. Working Capital related cash flows increased by $2.6 million during the first six months of 2007 compared to the same period in 2006. All other changes in operating activities were a net $3.5 million in sources of cash in the first six months of 2007 compared to 2006.

Table of Contents

Cash (Used in) Investing Activities	**$ (19.6)**	$ (14.4)

Cash (Used in) Investing Activities – Cash (Used in) Investing Activities was $19.6 million for the six months ended June 30, 2007, an increase of $5.2 million over the comparable period in 2006. Annual capital expenditures are projected to be $32.4 million in 2007 compared to $33.6 million expended in fiscal 2006. These 2007 projected capital expenditures include approximately $5.5 million of cash outlays for the Automated Metering Infrastructure (AMI) project, the second year of a two-year investment in the Company's advanced metering infrastructure. The Company's AMI expenditures were $5.4 million during the first six months of 2007 compared to $2.0 million during the comparable period in 2006. Capital expenditure projections are subject to changes during the fiscal year.

Cash Provided by Financing Activities	**$ 0.2**	$ 4.1

Cash Provided by Financing Activities – Cash Provided by Financing Activities was $0.2 million in the six months ended June 30, 2007, a decrease of $3.9 million over the comparable period in 2006. Cash provided from short term debt was $24.5 million lower in the first six months of 2007 compared to the same period in 2006, mainly due to the issuance of $20 million in Senior Long-Term Notes, as described above. All other cash flows provided from financing activities were a net $0.6 million higher in the first six months of 2007 compared to 2006.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 21, 2007.

Regulatory Accounting – The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDPU and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided below. Generally, the Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. Generally, the Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received.

Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDPU and NHPUC.

Regulatory Assets consist of the following (millions)	June 30, 2007	June 30, 2006	December 31, 2006
Power Supply Buyout Obligations	**$ 82.6**	$ 102.2	$ 92.6
Deferred Restructuring Costs	**30.1**	31.6	31.0
Generation-related Assets	**2.1**	2.9	2.5
Subtotal – Restructuring Related Items	**114.8**	136.7	126.1
Retirement Benefit Obligations	**37.2**	9.5	37.1
Income Taxes	**18.3**	16.8	19.1
Environmental Obligations	**13.1**	0.9	13.0
Other	**3.9**	3.7	3.5
Total Regulatory Assets	**$ 187.3**	$ 167.6	$ 198.8

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition – Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts – The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior periods. Account write-offs and recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Retirement Benefit Obligations – The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements (See Note 8.)

Income Taxes – Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) which is the authoritative pronouncement on accounting for and reporting income taxes.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise's financial statements. FIN 48 prescribes a "more-likely-than-not" recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition and classification. The Company adopted FIN 48 as of January 1, 2007, as required. The adoption of FIN 48 did not have a significant impact on the Company's financial position and results of operations.

Depreciation – Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies – The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of March 31, 2007, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Table of Contents

Refer to "Recently Issued Accounting Pronouncements' in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company's debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company's short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company's interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company's short-term borrowings for the three months ended June 30, 2007 and June 30, 2006 were 5.77% and 5.46%, respectively. The average interest rates on the Company's short-term borrowings for the six months ended June 30, 2007 and June 30, 2006 were 5.77% and 5.24%, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Table of Contents

Item 1. *Financial Statements*

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Operating Revenues				
Electric	**$ 51.7**	$ 53.4	**$ 114.4**	$ 109.8
Gas	**6.4**	6.3	**20.6**	20.0
Other	**0.9**	0.6	**1.8**	1.2
Total Operating Revenues	**59.0**	60.3	**136.8**	131.0
Operating Expenses				
Purchased Electricity	**36.3**	37.7	**84.5**	80.5
Purchased Gas	**3.9**	4.3	**13.7**	14.4
Operation and Maintenance	**6.8**	7.2	**13.3**	13.5
Conservation & Load Management	**1.1**	1.2	**2.1**	2.0
Depreciation and Amortization	**4.4**	4.4	**8.9**	8.6
Provisions for Taxes:				
Local Property and Other	**1.4**	1.5	**2.9**	2.9
Federal and State Income	**0.8**	0.6	**2.4**	1.8
Total Operating Expenses	**54.7**	56.9	**127.8**	123.7
Operating Income	**4.3**	3.4	**9.0**	7.3
Non-Operating Expenses (Income)	**0.1**	(0.1)	**0.1**	(0.1)
Income Before Interest Expense	**4.2**	3.5	**8.9**	7.4
Interest Expense, Net	**2.4**	2.0	**4.5**	3.9
Net Income	**1.8**	1.5	**4.4**	3.5
Less: Dividends on Preferred Stock	**0.1**	0.1	**0.1**	0.1
Earnings Applicable to Common Shareholders	**$ 1.7**	$ 1.4	**$ 4.3**	$ 3.4
Average Common Shares Outstanding - Basic (000's)	**5,642**	5,593	**5,634**	5,585
Average Common Shares Outstanding - Diluted (000's)	**5,663**	5,607	**5,653**	5,599
Earnings Per Common Share (Basic and Diluted)	**$ 0.30**	$ 0.25	**$ 0.76**	$ 0.61
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.035**	$ 1.035

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

[Table of Contents](#)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) June 30, 2007	June 30, 2006	December 31, 2006
ASSETS:			
Utility Plant:			
Electric	**$ 259.2**	$ 240.0	$ 250.3
Gas	**64.6**	59.5	63.5
Common	**25.6**	25.8	25.2
Construction Work in Progress	**21.5**	11.7	14.0
Total Utility Plant	**370.9**	337.0	353.0
Less: Accumulated Depreciation	**127.1**	116.8	121.2
Net Utility Plant	**243.8**	220.2	231.8
Current Assets:			
Cash	**2.2**	3.9	4.6
Accounts Receivable - Net of Allowance for Doubtful Accounts of $2.4, $1.2 and $1.7	**21.7**	23.0	22.5
Accrued Revenue	**9.0**	8.7	13.8
Materials and Supplies	**3.3**	3.5	4.5
Prepayments and Other	**1.8**	1.9	1.3
Total Current Assets	**38.0**	41.0	46.7
Noncurrent Assets:			
Regulatory Assets	**187.3**	167.6	198.8
Prepaid Pension Costs	**—**	9.8	—
Debt Issuance Costs	**2.8**	2.3	2.6
Other Noncurrent Assets	**1.9**	3.5	3.5
Total Noncurrent Assets	**192.0**	183.2	204.9
TOTAL	**$ 473.8**	$ 444.4	$ 483.4

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) June 30, 2007	(UNAUDITED) June 30, 2006	December 31, 2006
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 96.9**	$ 94.6	$ 97.8
Preferred Stock, Non-Redeemable, Non-Cumulative	**0.2**	0.2	0.2
Preferred Stock, Redeemable, Cumulative	**1.8**	1.9	1.9
Long-Term Debt, Less Current Portion	**160.0**	125.2	140.0
Total Capitalization	**258.9**	221.9	239.9
Current Liabilities:			
Long-Term Debt, Current Portion	**0.3**	0.3	0.3
Accounts Payable	**15.1**	19.7	19.8
Short-Term Debt	**9.5**	26.7	26.0
Taxes Payable	**2.4**	0.6	0.9
Interest and Dividends Payable	**3.8**	3.4	1.6
Other Current Liabilities	**4.4**	4.4	4.8
Total Current Liabilities	**35.5**	55.1	53.4
Deferred Income Taxes	**31.9**	51.0	34.5
Noncurrent Liabilities:			
Power Supply Contract Obligations	**82.6**	102.2	92.6
Retirement Benefit Obligations	**51.3**	12.9	49.7
Environmental Obligations	**12.0**	—	12.0
Other Noncurrent Liabilities	**1.6**	1.3	1.3
Total Noncurrent Liabilities	**147.5**	116.4	155.6
TOTAL	**$ 473.8**	$ 444.4	$ 483.4

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

Table of Contents

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Operating Activities:		
Net Income	**$ 4.4**	$ 3.5
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**8.9**	8.6
Deferred Taxes	**(2.3)**	(1.0)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**0.8**	0.6
Accrued Revenue	**4.8**	0.2
Accounts Payable	**(4.7)**	(0.9)
Taxes Payable	**1.5**	0.9
All other Current Assets and Liabilities	**0.5**	(0.5)
Other, net	**3.1**	(0.4)
Cash Provided by Operating Activities	**17.0**	11.0
Investing Activities:		
Property, Plant and Equipment Additions	**(19.6)**	(14.4)
Cash (Used in) Investing Activities	**(19.6)**	(14.4)
Financing Activities:		
Proceeds from (Repayment) of Short-Term Debt, net	**(16.5)**	8.0
Proceeds from Issuance of Long-Term Debt	**20.0**	—
Repayment of Long-Term Debt	**—**	(0.2)
Dividends Paid	**(4.0)**	(3.9)
Issuance of Common Stock	**0.5**	0.5
Retirement of Preferred Stock	**(0.1)**	(0.2)
Other, net	**0.3**	(0.1)
Cash Provided by Financing Activities	**0.2**	4.1
Net Increase (Decrease) in Cash	**(2.4)**	0.7
Cash at Beginning of Period	**4.6**	3.2
Cash at End of Period	**$ 2.2**	$ 3.9
Supplemental Cash Flow Information:		
Interest Paid	**$ 5.7**	$ 5.4
Income Taxes Paid	**$ 3.3**	$ 1.9

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and six months ended June 30, 2007 are not necessarily indicative of results to be expected for the year ending December 31, 2007. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2006, as filed with the SEC on February 21, 2007, for a description of the Company's Basis of Presentation.

Nature of Operations – Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In February 2007, the FASB issued FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." (SFAS No. 159), effective for fiscal years beginning after November 15, 2007. SFAS No. 159 includes an amendment of FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities." SFAS No. 159 permits entities to choose, at specified election dates, to measure eligible items at fair value and requires unrealized gains and losses on items for which the fair value option has been elected to be reported in earnings. The Company does not expect SFAS No. 159 to have a material impact on the Company's Consolidated Financial Position.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in enterprise's financial statements. FIN 48 prescribes a "more-likely-than-not" recognition threshold for the recognition and measurement of the benefits of a tax position taken or expected to be taken. FIN 48 is now the primary guidance in accounting for uncertainty in income taxes. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition, and classification. The Company adopted FIN 48 as of January 1, 2007, as required. The adoption of FIN 48 did not have a significant impact on the Company's financial position and results of operations. See Note 9.

Table of Contents

In September 2006, the FASB issued FASB Statement No. 157, "Fair Value Measurements", (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect SFAS No. 157 to have an impact on the Company's Consolidated Financial Statements.

In February 2006, the FASB issued FASB Statement No. 155, "Accounting for Certain Hybrid Financial Instruments", (SFAS No. 155), which amends SFAS No.133 and FASB Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities", (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company's adoption of SFAS No. 155 did not have an impact on the Company's Consolidated Financial Statements.

Reclassifications – Certain amounts previously reported have been reclassified to conform to current year presentation. The Company reclassified retirement benefit obligations from Other Noncurrent Liabilities to Retirement Benefit Obligations on the balance sheet and certain expenses between Purchased Electricity, Purchased Gas and Operations and Maintenance Expenses for presentation purposes.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount	
06/21/07	08/15/07	08/01/07	$	0.345
03/22/07	05/15/07	05/01/07	$	0.345
01/18/07	02/15/07	02/01/07	$	0.345
09/29/06	11/15/06	11/01/06	$	0.345
06/22/06	08/15/06	08/01/06	$	0.345
03/23/06	05/15/06	05/01/06	$	0.345
01/12/06	02/15/06	02/01/06	$	0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first six months of 2007, the Company sold 19,199 shares of its Common Stock, at an average price of $26.59 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $511,000 were used to reduce short-term borrowings.

During the first six months of 2006, the Company sold 20,816 shares of its Common Stock, at an average price of $24.64 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $513,000 were used to reduce short-term borrowings.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 9, 2007, 9,020 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $230,461. Compensation expense associated with annual grants of shares issued under the Plan is recognized on a monthly basis as the shares vest and was $0.2 million and $0.2 million for six months ended June 30, 2007 and 2006, respectively. At June 30, 2007, there was approximately $0.8 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 2.6 years as the shares vest.

Table of Contents

Details on preferred stock at June 30, 2007, June 30, 2006 and December 31, 2006 are shown below:

(Amounts in Millions)

	(Unaudited) June 30, 2007	June 30, 2006	December 31, 2006
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.9	0.9
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.0**	$ 2.1	$ 2.1

NOTE 4 – LONG-TERM DEBT

On May 2, 2007, Unitil Corporation issued and sold $20 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors in the form of a private placement. The proceeds from this long-term financing were used to refinance existing short-term debt and for general corporate purposes of the Company and its subsidiaries.

[Table of Contents](#)

Details on long-term debt at June 30, 2007, June 30, 2006 and December 31, 2006 are shown below:

(Amounts in Millions)

	(Unaudited) June 30, 2007	(Unaudited) June 30, 2006	December 31, 2006
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**$ 15.0**	$ 15.0	$ 15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	—	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Unitil Corporation:			
Senior Notes:			
6.33% Notes, Due May 1, 2022	**20.0**	—	—
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5.3**	5.5	5.3
Total	**160.3**	125.5	140.3
Less: Installments due within one year	**0.3**	0.3	0.3
Total Long-term Debt	**$ 160.0**	$ 125.2	$ 140.0

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at June 30, 2007 is estimated to be in a range of up to approximately $168 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to the duration of the contracts, which range from three months to three years. As of June 30, 2007 there are $12.5 million of guarantees outstanding and these guarantees extend through March 13, 2009. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

Table of Contents

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and six months ended June 30, 2007 and June 30, 2006 (Millions):

	Electric	Gas	Other	Non-Regulated	Total
Three Months Ended:					
June 30, 2007					
Revenues	**$ 51.7**	**$ 6.4**	**$ —**	**$ 0.9**	**$ 59.0**
Segment Profit (Loss)	**2.0**	**(0.4)**	**—**	**0.1**	**1.7**
Capital Expenditures	**8.0**	**1.5**	**0.5**	**—**	**10.0**
June 30, 2006					
Revenues	$ 53.4	$ 6.3	$ —	$ 0.6	$ 60.3
Segment Profit (Loss)	1.7	(0.4)	0.2	(0.1)	1.4
Capital Expenditures	6.4	2.3	0.1	—	8.8
Six Months Ended:					
June 30, 2007					
Revenues	**$ 114.4**	**$ 20.6**	**$ —**	**$ 1.8**	**$ 136.8**
Segment Profit (Loss)	**3.4**	**0.7**	**0.1**	**0.1**	**4.3**
Capital Expenditures	**17.1**	**2.2**	**0.3**	**—**	**19.6**
Segment Assets	**339.5**	**110.6**	**22.6**	**1.1**	**473.8**
June 30, 2006					
Revenues	$ 109.8	$ 20.0	$ —	$ 1.2	$ 131.0
Segment Profit (Loss)	3.0	0.3	0.3	(0.2)	3.4
Capital Expenditures	11.6	2.7	0.1	—	14.4
Segment Assets	322.8	100.7	19.7	1.2	444.4

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2006 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 21, 2007.

FG&E – Electric Division – On December 1, 2006, FG&E submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. This filing is pending, subject to investigation. On May 25, 2007 the MDPU approved FG&E's 2005 filing. The Company expects that its 2006 filing will be approved without material changes or adjustments.

On July 18, 2007, FG&E filed a Notice of Intent to File Rate Schedule Changes for its electric division pursuant to G.L. c. 164, s. 94 and Department Order D.P.U. 19019-A. This notice is required 30 days in advance of when FG&E expects to file for a distribution rate increase.

FG&E – Gas Division – On January 26, 2007, the MDPU approved a rate Settlement Agreement (Settlement) between FG&E and the Attorney General of Massachusetts for FG&E's Gas Division. Under the Settlement, FG&E increased its gas distribution rates by $1.2 million on February 1, 2007, and an additional $1.0 million increase will occur on November 1, 2007. The Settlement also includes agreement on several other rate matters and service quality performance measures for the company's Gas Division in the areas of safety, customer service and satisfaction.

On September 7, 2006, the MDPU issued an order allowing FG&E to recover the costs of its actual gas and electric supply-related bad debt effective December 1, 2005. Prior to this final approval, FG&E had recovered supply-related bad debt costs based on a fixed rate formula that produced a significant under-recovery of these costs. On September 27, 2006, the Attorney General filed a Petition for Appeal with the Massachusetts Supreme Judicial Court seeking to set aside the MDPU's order. FG&E intends to support the MDPU's order but the Company cannot predict the outcome of the Attorney General's appeal at this time.

FG&E – Other – On June 22, 2007, the MDPU opened an investigation to review ratemaking practices for gas and electric utility distribution companies in Massachusetts, and consider whether existing mechanisms may be changed to better align utility companies' financial interests with the need to capture end use efficiencies and foster the advancement of price responsive demand in the wholesale energy market. This matter remains pending.

UES – On March 16, 2007, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2007, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. On April 30, 2007 the NHPUC approved UES' filing subject to adjustment and reconciliation depending on the Staff audit and Staff's on-going review with regard to the method for calculating unbilled revenues. No exceptions were noted in the final audit report, which was issued on July 11, 2007.

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement (Agreement) resolving its electric distribution base rate case filed in November, 2005. The terms of the Agreement provide for an increase in base distribution rates of $2.3 million effective as of January 1, 2006. Additionally, the Agreement authorizes two step increases in base distribution rates, related to utility plant additions in 2006, of approximately $0.4 million and $0.1 million annually, effective as of November 1, 2006 and May 1, 2007, respectively. Also, the Agreement provides for the recovery of approximately $0.3 million annually of supply-related operating and administrative costs through default energy service rates and a reduction of approximately $0.6 million in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives. The stipulated rate of return under the settlement is 8.70%, including a return on equity of 9.67%. The Agreement also authorized a temporary rate surcharge for recovery of certain rate case expenses and recoupment of the authorized distribution rate increase from January through October 2006.

On June 22, 2007, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. This order sets the framework for implementation of time based rates for utility provided default service, though a number of technical issues remain to be resolved. UES is required to file draft tariffs to provide for fixed, time-based pricing of default service for all customer classes no later than November 30, 2007.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting, for electric utilities, appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. The matter remains pending.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2006 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 21, 2007.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of June 30, 2007, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at June 30, 2007 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetss. A corresponding regulatory asset was recorded to reflect the future rate recovery of these costs. As noted above, please refer to Note 5 to the financial statements in Item 8 of Part II of the Company's Form 10-K for December 31, 2006 for additional information.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit pension plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

In September 2006, the FASB issued SFAS No. 158 which requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

Pension Plan – The Company's defined benefit pension plan covers substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.

FG&E recovers the costs associated with its pension and PBOP costs on an annually reconciling basis through a rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF). FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106 and amortizes increases and/or decreases in that deferral balance into the PAF for recovery over a three year period.

UES recovers its pension and PBOP expenses in base rates and amortizes deferred pension costs as these costs are recovered over a six year period in base rates.

The following tables show the components of net periodic pension cost, (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Components of NPPC (000's)				
Service Cost	**$ 492**	$ 450	**$ 984**	$ 900
Interest Cost	**834**	790	**1,669**	1,577
Expected Return on Plan Assets	**(1,050)**	(976)	**(2,097)**	(1,887)
Amortization of Prior Service Cost	**27**	27	**53**	53
Amortization of Net Loss	**336**	306	**672**	662
Subtotal NPPC	**639**	597	**1,281**	1,305
Amounts Capitalized and Deferred	**(219)**	(68)	**(436)**	(644)
NPPC Recognized	**$ 420**	$ 529	**$ 845**	$ 661

Key Assumptions (Weighted Average)	2007	2006
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Used to Determine NPPC:		
Discount Rate	**5.50%**	5.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%
Rate of Compensation Increase	**3.50%**	3.50%

Employer Contributions – On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92%—100%) funding targets available to well-funded plans during the transition period. As of June 30, 2007, the Company has made contributions of $1.1 million to the Plan in 2007. The Company presently anticipates contributing an additional $1.7 million to fund the Plan in 2007, for an estimated total of $2.8 million for the year. The Company contributed $2.5 million in 2006.

PBOP Plan – The Company sponsors the PBOP Plan, primarily to provide health care and life insurance benefits to employees and retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Components of NPPBC (000's)				
Service Cost	**$ 358**	$ 350	**$ 715**	$ 641
Interest Cost	**514**	563	**1,028**	1,014
Expected Return on Plan Assets	**(61)**	(69)	**(122)**	(97)
Amortization of Prior Service Cost	**340**	340	**679**	680
Amortization of Transition (Asset) Obligation	**5**	5	**11**	11
Amortization of Net (Gain) Loss	**17**	80	**35**	80
Subtotal NPPBC	**1,173**	1,269	**2,346**	2,329
Amounts Capitalized and Deferred	**(504)**	(631)	**(1,017)**	(1,113)
NPPBC Recognized	**$ 669**	$ 638	**$ 1,329**	$ 1,216

Table of Contents

Weighted-Average Assumptions	2007	2006
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	5.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2016
Used to Determine NPPBC:		
Discount Rate	**5.50%**	5.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%/5.50% (1)**	8.50%/5.50% (1)
Health Care Cost Trend Rate Assumed for Next Year	**9.00%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2016

(1) Funding of the PBOP Plan is made into two VEBT's; one is a union VEBT and the other is a non-union VEBT. The expected long-term rate of return on plan assets for the union VEBT is 8.50%. The non-union VEBT is subject to income taxes and therefore the expected long-term rate of return on plan assets is 5.50%, reflecting the effect of taxes.

Employer Contributions – As of June 30, 2007, the Company had made $1.1 million of contributions to the PBOP Plan in 2007. The Company presently anticipates contributing an additional $1.4 million to fund the Plan in 2007 for an estimated funding total of $2.5 million in the year. The Company contributed $2.2 million in 2006.

SERP – The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors.

The components of net periodic SERP cost are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Components of NPSC (000's)				
Service Cost	**$ 41**	$ 36	**$ 82**	$ 72
Interest Cost	**29**	26	**59**	52
Amortization of Transition Obligation	**—**	4	**—**	9
Amortization of Prior Service Cost	**—**	—	**(1)**	(1)
Amortization of Net Loss	**11**	10	**22**	20
Net Periodic SERP Cost	**$ 81**	$ 76	**$ 162**	$ 152

Employer Contributions – As of June 30, 2007, the Company has made payments of $36,000 to beneficiaries. The Company presently anticipates making additional benefit payments of $36,000 in 2007 for a total of $72,000.

NOTE 9: INCOME TAXES

The Company evaluated its tax positions at December 31, 2006 and for the current interim reporting period ended June 30, 2007 in accordance with FIN 48, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2003; December 31, 2004; and December 31, 2005. Income tax filings for the year ended December 31, 2006 have been extended and are due September 15, 2007. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2006 as filed with the Securities and Exchange Commission on February 21, 2007.

Table of Contents

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended June 30, 2007.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
4/1/07 – 4/30/07	—	—	—	n/a
5/1/07 – 5/31/07	114	$ 27.75	114	n/a
6/1/07 – 6/30/07	—	—	—	n/a
Total	114	$ 27.75	114	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

[Table of Contents](#)

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated July 25, 2006 Announcing Earnings For the Quarter Ended June 30, 2007	Filed herewith

[Table of Contents](#)

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	UNITIL CORPORATION (Registrant)
Date: July 26, 2007	/s/ Mark H. Collin
	Mark H. Collin Chief Financial Officer
Date: July 26, 2007	/s/ Laurence M. Brock
	Laurence M. Brock Chief Accounting Officer

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Net Income	**$ 1.8**	$ 1.5	**$ 4.4**	$ 3.5
Less: Dividend Requirements on Preferred Stock	**0.1**	0.1	**0.1**	0.1
Net Income Applicable to Common Stock	**$ 1.7**	$ 1.4	**$ 4.3**	$ 3.4
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**5,642**	5,593	**5,634**	5,585
Dilutive Effect of Stock Options and Restricted Stock (000's)	**21**	14	**19**	14
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**5,663**	5,607	**5,653**	5,599
Earnings Per Share – Basic	**$ 0.30**	$ 0.25	**$ 0.76**	$ 0.61
Earnings Per Share – Diluted	**$ 0.30**	$ 0.25	**$ 0.76**	$ 0.61

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 26, 2007
/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 26, 2007
/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 26, 2007
/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending June 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	July 26, 2007
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	July 26, 2007
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	July 26, 2007

For Immediate Release

Exhibit 99.1

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports Second Quarter Earnings

Hampton, NH – July 25, 2007: Unitil Corporation (AMEX: UTL) (www.unitil.com) today announced net income of $1.7 million for the second quarter of 2007, an increase of $0.3 million over the second quarter of 2006. Earnings per common share (EPS) were $0.30 for the three months ended June 30, 2007, an improvement of $0.05 per share or 20% over the second quarter of 2006. Unitil's improved second quarter performance was driven by higher gas sales and lower operation and maintenance expenses, which were partially offset by higher interest expense. For the six months ended June 30, EPS were $0.76 for 2007 compared to $0.61 for 2006, an improvement of $0.15, or 25%.

Unitil's non-regulated business, Usource, also continued to realize higher revenues compared to last year, which further contributed to the Company's overall improved earnings.

"Unitil continued strong year over year earnings growth in the second quarter," said Bob Schoenberger, Unitil Chairman and CEO. "This growth in earnings was primarily driven by increased distribution revenues, lower operating expenses and robust growth in our Usource subsidiary. We also continue to work with regulatory officials and local utilities to more appropriately align distribution company financial interests with the current public policy objectives of increased investment in energy efficiency and renewable energy technologies."

The following table presents the significant items (discussed below) contributing to the improvement in earnings per share in the three and six month periods ended June 30, 2007:

2007 Earnings Per Share vs. 2006

	Period Ended June 30,	
	QTD	**YTD**
2006	**$ 0.25**	**$ 0.61**
Electric Sales Margin	(0.02)	0.04
Gas Sales Margin	0.06	0.14
Usource Sales Margin	0.03	0.06
Operation & Maintenance Expense	0.04	0.02
Depreciation, Amortization & Other	(0.02)	(0.05)
Interest Expense, Net	(0.04)	(0.06)
2007	**$ 0.30**	**$ 0.76**

Total electric kWh sales in the three and six month periods ended June 30, 2007 increased 0.5% and 0.1%, respectively, compared to the same periods in 2006. Gas sales in the three and six month periods ended June 30, 2007 increased 12.1% and 9.0%, respectively, compared to the same periods in 2006. Selected Financial Data for 2007 is presented in the following table:

(Unaudited)

Unitil Corporation – Condensed Financial Data

(Millions, except Per Share data)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2007	2006	Change	2007	2006	Change
Electric kWh Sales:						
Residential	152.0	149.7	1.5%	335.9	332.9	0.9%
Commercial/Industrial	262.5	262.8	(0.1%)	528.2	530.6	(0.5%)
Total	**414.5**	**412.5**	**0.5%**	**864.1**	**863.5**	**0.1%**
Gas Therm Sales:						
Residential	2.3	2.0	15.0%	7.2	6.9	4.3%
Commercial/Industrial	4.2	3.8	10.5%	11.0	9.8	12.2%
Total	**6.5**	**5.8**	**12.1%**	**18.2**	**16.7**	**9.0%**
Electric Revenues	$ 51.7	$ 53.4	$ (1.7)	$ 114.4	$ 109.8	$ 4.6
Purchased Electricity	37.3	38.8	(1.5)	86.5	82.4	4.1
Electric Sales Margin	**14.4**	**14.6**	**(0.2)**	**27.9**	**27.4**	**0.5**
Gas Revenues	6.4	6.3	0.1	20.6	20.0	0.6
Purchased Gas	4.0	4.4	(0.4)	13.8	14.5	(0.7)
Gas Sales Margin	**2.4**	**1.9**	**0.5**	**6.8**	**5.5**	**1.3**
Usource Sales Margin	**0.9**	**0.6**	**0.3**	**1.8**	**1.2**	**0.6**
Total Sales Margin:	**17.7**	**17.1**	**0.6**	**36.5**	**34.1**	**2.4**
Operation & Maintenance Expenses	6.8	7.2	(0.4)	13.3	13.5	(0.2)
Depreciation, Amortization & Other	6.8	6.5	0.3	14.4	13.3	1.1
Interest Expense, Net	2.4	2.0	0.4	4.5	3.9	0.6
Net Income:	**$ 1.7**	**$ 1.4**	**$ 0.3**	**$ 4.3**	**$ 3.4**	**$ 0.9**
Earnings Per Share	**$ 0.30**	**$ 0.25**	**$ 0.05**	**$ 0.76**	**$ 0.61**	**$ 0.15**

Electric sales margin decreased $0.2 million and increased $0.5 million in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006. The lower electric sales margin in the second quarter of 2007 is due to the timing of recognition, in the second quarter of 2006, of revenues retroactive to January 1, 2006 associated with higher new electric rates established in the Company's electric rate case settlement in New Hampshire. The overall electric sales margin improvement through the first six months of 2007 compared to 2006 reflects additional step rate increases approved and implemented in the last half of 2006 and the first half of 2007.

Gas sales margin increased $0.5 million and $1.3 million in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006 reflecting higher gas sales due to more normal winter weather than last year and higher gas revenue from new higher rates approved and implemented in early 2007.

Usource, Unitil's non-regulated energy brokering business, recorded increased sales of $0.3 million and $0.6 million in the three and six month periods ended June 30, 2007 compared to the same periods of 2006, representing increases of 50% over the comparable 2006 periods.

Total Operation and Maintenance (O&M) expenses decreased $0.4 million and $0.2 in the three and six month periods ended June 30, 2007 compared to the same periods in 2006. The decrease in the six month period reflects lower outside services expenses of $0.3 million as well as cost efficiencies achieved in utility operating and all other expenses of $0.3 million, net, partially offset by higher salaries and compensation expenses of $0.3 million and higher retiree and employee benefit costs of $0.1 million.

Depreciation, Amortization & Other expenses increased $0.3 million and $1.1 million in the three and six month periods ended June 30, 2007 compared to the same periods in 2006 primarily reflecting higher depreciation on utility plant additions and higher income taxes on higher levels of pre-tax earnings in 2007 compared to 2006.

Interest Expense, Net increased $0.4 million and $0.6 million in the three and six month periods ended June 30, 2007 compared to the same periods in 2006 reflecting an increase in the average cost of debt and higher long-term debt outstanding.

Also in the second quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

About Unitil

Unitil is a public utility holding company with subsidiaries providing electric service in New Hampshire and electric and gas service in Massachusetts and energy services throughout the Northeast. Its subsidiaries include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Unitil Power Corp., Unitil Realty Corp., Unitil Service Corp. and its non-regulated business segment Unitil Resources, Inc. Usource L.L.C. is a subsidiary of Unitil Resources, Inc.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended September 30, 2007

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X__

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 25, 2007
Common Stock, No par value	5,730,869 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended September 30, 2007

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through two utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with an operating franchise in the southeastern seacoast and capital city areas of New Hampshire. FG&E is a combination gas and electric utility with an operating franchise in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 99,400 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are pure distribution utilities with a combined investment in net utility plant of $246.6 million at September 30, 2007. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource™ (Usource) subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

RATES AND REGULATION

Unitil's utility operations related to wholesale and interstate business activities are regulated by the Federal Energy Regulatory Commission (FERC). The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Public Utilities (MDPU), formerly the Massachusetts Department of Telecommunications and Energy, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets.

As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities provide for the delivery of that supply of electricity over their distribution systems at regulated rates. Both UES and FG&E continue to provide basic or default electric supply service to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without

limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' future performance under multi-year energy brokering contracts.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2006 as filed with the Securities and Exchange Commission on February 21, 2007.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended September 30, 2007 and September 30, 2006 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 1 of this report.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $1.6 million for the third quarter of 2007. Earnings per common share (EPS) were $0.28 for the three months ended September 30, 2007 compared with $0.32 in the third quarter of 2006. Earnings for the third quarter of 2007 reflect higher depreciation and interest expenses, partially offset by higher electric and gas utility sales margins and improved profits from Usource, Unitil's non-regulated energy-brokering business. For the nine months ended September 30, EPS were $1.04 for 2007 compared to $0.93 for 2006, an increase of $0.11 per share, or 12%.

The following table presents the significant items (discussed below) contributing to the change in earnings per share in the three and nine month periods ended September 30, 2007:

2007 Earnings Per Share vs. 2006

		Period Ended September 30,	
		QTD	**YTD**
	2006	**$ 0.32**	**$ 0.93**
Electric Sales Margin		0.03	0.07
Gas Sales Margin		0.02	0.16
Usource Sales Margin		0.04	0.10
Operation & Maintenance Expense		---	0.02
Depreciation, Amortization & Other		(0.09)	(0.14)
Interest Expense, Net		(0.04)	(0.10)
	2007	**$ 0.28**	**$ 1.04**

Unitil's total electric kilowatt (kWh) sales decreased 3.9% and 1.4% in the three and nine month periods ended September 30, 2007, respectively compared to the same periods in 2006. The lower kWh sales in 2007 compared to 2006 were primarily driven by cooler summer weather this year and energy conservation by our residential and commercial and industrial (C&I) customers. Electric kWh sales to residential customers in the three and nine month periods ended September 30, 2007 decreased 4.7% and 1.1%, respectively, compared to the same periods in 2006 while sales to C&I customers decreased 3.3% and 1.5% in those periods compared to the same periods in 2006. Natural gas sales in the three and nine month periods ended September 30, 2007 increased 6.1% and 8.0%, respectively, compared to the same periods in 2006. The increase in gas sales in 2007 reflects a colder winter heating season this year and higher natural gas sales to C&I customers.

Electric sales margin increased $0.3 million and $0.7 million in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006. The improvement in electric sales margin primarily reflects additional step rate increases approved and implemented in the last half of 2006 and the first half of 2007 in New Hampshire, partially offset by lower electric kWh sales volumes.

Natural gas sales margin increased $0.2 million and $1.6 million in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006 primarily reflecting higher sales to commercial and industrial customers and new natural gas distribution rates approved and implemented in early 2007.

Usource increased revenues by $0.4 million and $1.0 million in the three and nine month periods ended September 30, 2007, increases of 67% and 56% respectively, over the comparable 2006 periods.

Total O&M expenses were flat for the three month period ended September 30, 2007 compared to the same period in 2006. For the nine month period ended September 30, 2007, total O&M expenses decreased $0.2 million compared to the same period in 2006. This decrease reflects lower Distribution Utility labor and operating expenses of $0.5 million in 2007 as the Company is realizing savings as a result of its recent significant investments in Automated Metering Infrastructure (AMI) improvements; as well as lower outside services expenses of $0.2 million, and lower bad debt expenses of $0.1 million and all other operating expenses of $0.3 million. These lower O&M costs were partially offset by higher retiree and employee benefit costs of $0.5 million and higher salaries and compensation expenses of $0.4 million in 2007.

Depreciation, Amortization, Taxes & Other expenses increased $0.7 million and $1.8 million in the three and nine month periods ended September 30, 2007 compared to the same periods in 2006 reflecting higher depreciation on utility plant and income taxes on higher levels of pre-tax earnings in 2007 compared to 2006. The higher depreciation on utility plant includes depreciation expense on normal plant additions in 2007 and the recognition, in the third quarter of 2006, of a non-recurring adjustment for lower depreciation rates on utility plant established in the Company's electric rate case settlement in New Hampshire.

Interest Expense, Net increased $0.4 million and $1.0 million in the three and nine month periods ended September 30, 2007 compared to the same periods in 2006 reflecting higher debt outstanding and higher interest rates.

Also in the third quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

A more detailed discussion of the Company's results of operations for the three and nine months ended September 30, 2007 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

Regulatory Assets increased $19.3 million as of September 30, 2007 compared to September 30, 2006, reflecting the recording of Regulatory Assets for Retirement Benefit Obligations in accordance with newly issued Federal Accounting Standards Board (FASB) Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158) (See Note 8) and the recording of a Regulatory Asset for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts (See Note 7), partially offset by a decrease related to current year cost recoveries.

Long-Term Debt increased $19.7 million as of September 30, 2007 compared to September 30, 2006, reflecting the issuance and sale on May 2, 2007 by Unitil Corporation of $20 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors, in the form of a private placement.

Deferred Income Taxes decreased $19.1 million as of September 30, 2007 compared to September 30, 2006, primarily reflecting the recording of deferred tax assets related to Retirement Benefit Obligations, discussed below.

Retirement Benefit Obligations increased $37.0 million as of September 30, 2007 compared to September 30, 2006, primarily reflecting the recording of pension, PBOP and SERP obligations in accordance with SFAS No. 158, discussed above.

Environmental Obligations increased $12.0 million as of September 30, 2007 compared to September 30, 2006, reflecting the recording of a liability for future environmental remediation obligations associated with the Company's former manufactured gas plant site at Sawyer Passway, discussed above.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Unitil's total electric kWh sales decreased 3.9% and 1.4% in the three and nine month periods ended September 30, 2007, respectively compared to the same periods in 2006. The lower kWh sales in 2007 compared to 2006 were primarily driven by cooler summer weather this year and energy conservation by our residential and commercial and industrial (C&I) customers. Electric kWh sales to residential customers in the three and nine month periods ended September 30, 2007 decreased 4.7% and 1.1%, respectively, compared to the same periods in 2006 while sales to C&I customers decreased 3.3% and 1.5% in those periods compared to the same periods in 2006.

The following table details total kWh sales for the three and nine months ended September 30, 2007 and 2006 by major customer class:

kWh Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2007	2006	Change	% Change	**2007**	2006	Change	% Change
Residential	**179.7**	188.6	(8.9)	(4.7%)	**515.6**	521.5	(5.9)	(1.1%)
Commercial / Industrial	**285.1**	294.9	(9.8)	(3.3%)	**813.2**	825.5	(12.3)	(1.5%)
Total	**464.8**	483.5	(18.7)	(3.9%)	**1,328.8**	1,347.0	(18.2)	(1.4%)

Electric Operating Revenues and Sales Margin - The following table details total Electric Operating Revenues and Sales Margin for the three and nine month periods ended September 30, 2007 and 2006:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2007	2006	$ Change	% Change[1]	**2007**	2006	$ Change	% Change[1]
Electric Operating Revenue:								
Residential	**$ 29.5**	$ 29.3	$ 0.2	0.3%	**$ 85.7**	$ 76.9	$ 8.8	5.1%
Commercial / Industrial	**27.4**	31.9	(4.5)	(7.4%)	**85.6**	94.1	(8.5)	(5.0%)
Total Electric Operating Revenue	**$ 56.9**	$ 61.2	$ (4.3)	(7.1%)	**$ 171.3**	$ 171.0	$ 0.3	0.1%
Cost of Electric Sales:								
Purchased Electricity	**$ 41.9**	$ 46.4	$ (4.5)	(7.4%)	**$ 126.4**	$ 126.9	$ (0.5)	(0.3%)
Conservation & Load Management	**0.8**	0.9	(0.1)	(0.2%)	**2.8**	2.7	0.1	0.1%
Electric Sales Margin	**$ 14.2**	$ 13.9	$ 0.3	0.5%	**$ 42.1**	$ 41.4	$ 0.7	0.3%

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues, decreased by $4.3 million, or 7.1%, and increased by $0.3 million, or 0.1%, in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net decrease in Total Electric Operating Revenues in the three month period reflects lower Purchased Electricity costs of $4.5 million and lower C&LM revenues of $0.1 million, partially offset by higher sales margin of $0.3 million. The net increase in Total Electric Operating Revenues in the nine month period reflects lower Purchased Electricity costs of $0.5 million offset by higher C&LM revenues of $0.1 million and higher sales margin of $0.7 million.

Purchased Electricity and C&LM revenues decreased a net $4.6 million, or 7.6%, and $0.4 million, or 0.2%, of Total Electric Operating Revenues in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006. These decreases primarily reflect an increase in the amount of electricity purchased by customers directly from third-party suppliers partially offset by higher electric commodity prices. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $0.3 million and $0.7 million in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006. The improvement in electric sales margin primarily reflects additional step rate increases approved and implemented in the last half of 2006 and the first half of 2007 in New Hampshire, partially offset by lower electric kWh sales volumes.

Gas Sales, Revenues and Margin

Therm Sales – Unitil's total therm sales of natural gas increased 6.1% and 8.0% in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006. The increase in gas sales in 2007 reflects a colder winter heating season this year and higher natural gas sales to C&I customers. Gas sales to residential customers in the three month period ended September 30, 2007 were essentially unchanged compared to the same period in 2006 and increased 2.6% in the nine month period ended September 30, 2007, compared to the same period in 2006 while sales to C&I customers increased 7.7% and 11.3% in those periods compared to the same periods in 2006.

The following table details total firm therm sales for the three and nine months ended September 30, 2007 and 2006, by major customer class:

Therm Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2007	2006	Change	% Change	**2007**	2006	Change	% Change
Residential	**0.7**	0.7	---	---	**7.9**	7.7	0.2	2.6%
Commercial / Industrial	**2.8**	2.6	0.2	7.7%	**13.8**	12.4	1.4	11.3%
Total	**3.5**	3.3	0.2	6.1%	**21.7**	20.1	1.6	8.0%

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and nine months ended September 30, 2007 and 2006:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2007	2006	$ Change	% Change(1)	**2007**	2006	$ Change	% Change(1)
Gas Operating Revenue:								
Residential	**$ 2.3**	$ 2.0	$ 0.3	6.8%	**$ 14.7**	$ 13.0	$ 1.7	7.0%
Commercial / Industrial	**1.6**	2.4	(0.8)	(18.2%)	**9.8**	11.4	(1.6)	(6.6%)
Total Gas Operating Revenue	**$ 3.9**	$ 4.4	$ (0.5)	(11.4%)	**$ 24.5**	$ 24.4	$ 0.1	0.4%
Cost of Gas Sales:								
Purchased Gas	**$ 2.1**	$ 2.8	$ (0.7)	(15.9%)	**$ 15.8**	$ 17.2	$ (1.4)	(5.7%)
Conservation & Load Management	**---**	---	---	---	**0.1**	0.2	(0.1)	(0.4%)
Gas Sales Margin	**$ 1.8**	$ 1.6	$ 0.2	4.5%	**$ 8.6**	$ 7.0	$ 1.6	6.5%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues decreased $0.5 million, or 11.4%, and increased $0.1 million, or 0.4%, in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net decrease in Total Gas Operating Revenues in the three month period reflects lower Purchased Gas costs of $0.7 million partially offset by higher sales margin of $0.2 million. The net increase in Total Gas Operating Revenues in the nine month period reflects higher sales margin of $1.6 million, partially offset by lower Purchased Gas costs of $1.4 million and lower C&LM revenues of $0.1 million.

Purchased Gas and C&LM revenues decreased a net $0.7 million, or 15.9%, and $1.5 million, or 6.1%, of Total Gas Operating Revenues in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006, reflecting lower natural gas commodity prices and an increase in the amount of natural gas purchased by customers directly from third-party suppliers. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $0.2 million and $1.6 million in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006 primarily reflecting higher sales to commercial and industrial customers and new natural gas distribution rates approved and implemented in early 2007.

Operating Revenue - Other

The following table details total Other Revenue for the three and nine months ended September 30, 2007 and 2006:

Other Revenue (000's)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2007	2006	$ Change	% Change	**2007**	2006	$ Change	% Change
Other	**$ 1.0**	$ 0.6	$ 0.4	66.7%	**$ 2.8**	$ 1.8	$ 1.0	55.6%
Total Other Revenue	**$ 1.0**	$ 0.6	$ 0.4	66.7%	**$ 2.8**	$ 1.8	$ 1.0	55.6%

Total Other Revenue increased $0.4 million, or 66.7%, and $1.0 million, or 55.6% in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006. These increases were the result of growth in revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity decreased $4.5 million, or 9.7% and $0.5 million, or 0.4%, in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006. These decreases reflect lower electric kWh sales and an increase in the amount of electricity purchased by customers directly from third-party suppliers, partially offset by higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $0.7 million, or 25.0%, and $1.4 million, or 8.1%, in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006. These decreases in Purchased Gas are attributable to lower natural gas commodity prices and an increase in the amount of natural gas purchased by customers directly from third-party suppliers. The

Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expenses were flat for the three month period ended September 30, 2007 compared to the same period in 2006. For the nine month period ended September 30, 2007, total O&M expenses decreased $0.2 million compared to the same period in 2006. This decrease reflects lower Distribution Utility labor and operating expenses of $0.5 million in 2007 as the Company is realizing savings as a result of its recent significant investments in Automated Metering Infrastructure (AMI) improvements; as well as, lower outside services expenses of $0.2 million, lower bad debt expenses of $0.1 million and all other operating expenses of $0.3 million, net, partially offset by higher retiree and employee benefit costs of $0.5 million (driven by higher pension and postretirement benefit costs other than pension (PBOP) costs of $1.1 million, partially offset by lower medical and other benefit costs of $0.6 million) and higher salaries and compensation expenses of $0.4 million. The Company recovers its pension and PBOP costs through base distribution rates in New Hampshire. In Massachusetts, the Company recovers its pension and PBOP costs on a dollar for dollar basis through a recovery mechanism and therefore the revenue associated with the recovery of these costs is included in electric and gas sales margin.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased $0.1 million, or 11.1% in the three month period ended September 30, 2007 compared to the same period in 2006. This change reflects the timing of spending on the implementation of Energy Efficiency programs. Total C&LM expenses for the nine month period ended September 30, 2007 were unchanged compared to the same period in 2006. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense increased $1.1 million, or 32.4% and $1.4 million, or 11.7% in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006 reflecting higher depreciation on utility plant. The higher depreciation on utility plant includes depreciation expense on normal plant additions in 2007 and the recognition, in the third quarter of 2006, of a non-recurring adjustment for lower depreciation rates on utility plant established in the Company's electric rate case settlement in New Hampshire.

Local Property and Other Taxes - Local Property and Other Taxes were flat for the three and nine month periods ended September 30, 2007 compared to the same periods in 2006.

Federal and State Income Taxes - Federal and State Income Taxes were lower by $0.3 million in the three month period ended September 30, 2007 compared to the same period in 2006 reflecting lower pre-tax earnings. Federal and State Income Taxes were higher by $0.3 million in the nine month period ended September 30, 2007 compared to the same period in 2006 reflecting higher pre-tax earnings.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) decreased by less than $0.1 million in the three period ended September 30, 2007 compared to the same period in 2006. For the nine month period ended September 30, 2007, Other Non-operating Expenses (Income) increased by $0.1 million compared to the same period in 2006. This change reflects the recognition in 2006 of a gain on the sale of land and timber harvest revenue.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's rate tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (Millions)	**Three Months Ended September 30,**			**Nine Months Ended September 30,**		
	2007	2006	Change	**2007**	2006	Change
Interest Expense						
Long-term Debt	$ 2.9	$ 2.3	$ 0.6	$ 8.2	$ 7.0	$ 1.2
Short-term Debt	0.1	0.4	(0.3)	0.8	1.1	(0.3)
Regulatory Liabilities	0.1	0.1	---	0.4	0.2	0.2
Subtotal Interest Expense	3.1	2.8	0.3	9.4	8.3	1.1
Interest Income						
Regulatory Assets	(0.7)	(0.8)	0.1	(2.2)	(2.3)	0.1
AFUDC and Other	(0.1)	(0.1)	---	(0.4)	(0.2)	(0.2)
Subtotal Interest Income	(0.8)	(0.9)	0.1	(2.6)	(2.5)	(0.1)
Total Interest Expense, Net	$ 2.3	$ 1.9	$ 0.4	$ 6.8	$ 5.8	$ 1.0

Interest Expense, Net increased by $0.4 million and $1.0 million in the three and nine month periods ended September 30, 2007, respectively, compared to the same periods in 2006 reflecting an increase in the average cost of debt and higher debt outstanding. Interest expense on long-term borrowings increased in both the three and nine month periods in 2007 compared to 2006 due to the issuance of new fixed rate long-term debt. On May 2, 2007, Unitil Corporation issued and sold $20 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors in the form of a private placement. The proceeds from this fixed rate long-term financing were used to refinance existing variable rate short-term debt and for general corporate purposes of the Company and its subsidiaries, including the Company's investment in the AMI project. The higher interest costs associated with the higher levels of long-term debt are partially offset by labor cost savings in Distribution Utility operating expenses resulting from the AMI project. Interest expense on short-term debt decreased $0.3 million and $0.3 million in the three and nine month periods ended September 30, 2007 compared to the same periods in 2006 primarily due to lower average short-term borrowings.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. Long-term financings, mainly in the form of first mortgage bonds, unsecured notes and equity, are periodically issued to complement the addition of long-term plant investments and for other corporate purposes.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

On June 30, 2007 Unitil renewed $30 million in unsecured revolving lines of credit through three banks. Average daily short-term borrowings during the first nine months of 2007 were approximately $17.6 million, a decrease of approximately $7.8 million over the comparable period in 2006, reflecting principally the receipt of the Unitil Note financing proceeds in May 2007, described below.

On May 2, 2007, Unitil completed the sale of $20 million of Senior Long-Term Notes, through a private placement to institutional investors. The Notes have a term of 15 years maturity and a coupon rate of 6.33%. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other general corporate purposes of the Company's principal utility subsidiaries. On September 26, 2006 the Company's affiliate, UES sold $15 million of Series O 6.32% First Mortgage Bonds. The proceeds from this issuance were utilized to finance long-lived utility plant additions that had been previously financed by short-term indebtedness.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to the duration of the contracts, which range from less than one month to two and one-half years. As of September 30, 2007, there were approximately $8.3 million of guarantees outstanding and the longest term guarantee extends through March 13, 2009.

The tables below summarize the major sources and uses of cash (in millions) for the nine months ended September 30, 2007 compared to the same period in 2006.

Cash Provided by Operating Activities	**$**	**23.6**	$	17.0

Cash Provided by Operating Activities - Cash Provided by Operating Activities was $23.6 million during the first nine months ended September 30, 2007, an increase of $6.6 million over the comparable period in 2006. Sources of cash from Net Income were $0.7 million higher in the first nine months of 2007 compared to 2006. Sources of cash from Depreciation and Amortization increased by $1.4 million in the current period compared to the same period in 2006. An additional $1.3 million of cash was utilized for Deferred Taxes as compared to the comparable period in 2006. Working Capital related cash flows increased by $5.3 million during the first nine months of 2007 compared to the same period in 2006, principally due to recoveries of accrued revenue through reconciling mechanisms. All other changes in operating activities were a net $0.5 million in sources of cash in the first nine months of 2007 compared to 2006.

Cash (Used in) Investing Activities	**$**	**(25.9)**	$	(24.7)

Cash (Used in) Investing Activities - Cash (Used in) Investing Activities was $25.9 million for the nine months ended September 30, 2007, an increase of $1.2 million over the comparable period in 2006. Annual capital expenditures are projected to be $32.4 million in 2007 compared to $33.6 million expended in fiscal 2006. The

2007 projected capital expenditures include approximately $6.7 million of cash outlays for the last phase of investment for the AMI project. The Company's AMI expenditures were $5.9 million during the first nine months of 2007 compared to $4.5 million during the comparable period in 2006. Capital expenditure projections are subject to changes during the fiscal year.

Cash Provided by Financing Activities	**$ 1.9**	$ 8.3

Cash Provided by Financing Activities - Cash Provided by Financing Activities was $1.9 million in the nine months ended September 30, 2007, a decrease of $6.4 million over the comparable period in 2006. Cash provided from short term debt was $11.9 million lower at September 30, 2007, as compared to December 31, 2006, principally reflecting the issuance of $20 million in Senior Long-Term Notes in May 2007, as described above. Proceeds from Long-Term Debt issuances increased by $5 million in the current nine month period of 2007 compared to the same period last year, reflecting the net difference between the issuance of the $20 million 2007 Unitil Notes and $15 million 2006 UES Bond financings, described above. All other cash flows provided from other financing activities aggregated to a net $0.5 million increase in the first nine months of 2007 as compared to the same period in 2006.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 21, 2007.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDPU and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided below. Generally, the Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. Generally, the Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received.

Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDPU and NHPUC.

Regulatory Assets consist of the following (millions)	September 30, 2007	September 30, 2006	December 31, 2006
Power Supply Buyout Obligations	**$ 77.7**	$ 97.3	$ 92.6
Deferred Restructuring Costs	**29.5**	30.5	31.0
Generation-related Assets	**1.8**	2.7	2.5
Subtotal – Restructuring Related Items	**109.0**	130.5	126.1
Retirement Benefit Obligations	**37.3**	10.5	37.1
Income Taxes	**17.9**	16.4	19.1
Environmental Obligations	**13.1**	0.9	13.0
Other	**3.5**	3.2	3.5
Total Regulatory Assets	**$ 180.8**	$ 161.5	$ 198.8

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior periods. Account write-offs and recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Retirement Benefit Obligations - The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements (See Note 8.)

Income Taxes - Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) which is the authoritative pronouncement on accounting for and reporting income taxes.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition and classification. The Company adopted FIN 48 as of January 1, 2007, as required. The adoption of FIN 48 did not have a significant impact on the Company's financial position and results of operations.

Depreciation - Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies - The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of September 30, 2007, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company's debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company's short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company's interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company's short-term borrowings for the three months ended September 30, 2007 and September 30, 2006 were 5.71% and 5.82%, respectively. The average interest rates on the Company's short-term borrowings for the nine months ended September 30, 2007 and September 30, 2006 were 5.75% and 5.44%, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Operating Revenues				
Electric	**$ 56.9**	$ 61.2	**$ 171.3**	$ 171.0
Gas	**3.9**	4.4	**24.5**	24.4
Other	**1.0**	0.6	**2.8**	1.8
Total Operating Revenues	**61.8**	66.2	**198.6**	197.2
Operating Expenses				
Purchased Electricity	**41.9**	46.4	**126.4**	126.9
Purchased Gas	**2.1**	2.8	**15.8**	17.2
Operation and Maintenance	**6.5**	6.5	**19.8**	20.0
Conservation & Load Management	**0.8**	0.9	**2.9**	2.9
Depreciation and Amortization	**4.5**	3.4	**13.4**	12.0
Provisions for Taxes:				
Local Property and Other	**1.3**	1.3	**4.2**	4.2
Federal and State Income	**0.8**	1.1	**3.2**	2.9
Total Operating Expenses	**57.9**	62.4	**185.7**	186.1
Operating Income	**3.9**	3.8	**12.9**	11.1
Non-Operating Expenses	**---**	0.1	**0.1**	---
Income Before Interest Expense	**3.9**	3.7	**12.8**	11.1
Interest Expense, Net	**2.3**	1.9	**6.8**	5.8
Net Income	**1.6**	1.8	**6.0**	5.3
Less: Dividends on Preferred Stock	**---**	---	**0.1**	0.1
Earnings Applicable to Common Shareholders	**$ 1.6**	$ 1.8	**$ 5.9**	$ 5.2
Average Common Shares Outstanding – Basic (000's)	**5,659**	5,605	**5,643**	5,592
Average Common Shares Outstanding - Diluted (000's)	**5,668**	5,619	**5,659**	5,606
Earnings Per Common Share (Basic and Diluted)	**$ 0.28**	$ 0.32	**$ 1.04**	$ 0.93
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.38**	$ 1.38

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) September 30, 2007	September 30, 2006	December 31, 2006
ASSETS:			
Utility Plant:			
Electric	**$ 260.5**	$ 245.3	$ 250.3
Gas	**65.5**	60.7	63.5
Common	**25.8**	25.3	25.2
Construction Work in Progress	**24.2**	14.6	14.0
Total Utility Plant	**376.0**	345.9	353.0
Less: Accumulated Depreciation	**129.4**	118.4	121.2
Net Utility Plant	**246.6**	227.5	231.8
Current Assets:			
Cash	**4.2**	3.8	4.6
Accounts Receivable – Net of Allowance for Doubtful Accounts of $2.1, $1.3 and $1.7	**22.8**	22.6	22.5
Accrued Revenue	**9.5**	9.6	13.8
Materials and Supplies	**4.4**	4.2	4.5
Prepayments and Other	**1.2**	1.2	1.3
Total Current Assets	**42.1**	41.4	46.7
Noncurrent Assets:			
Regulatory Assets	**180.8**	161.5	198.8
Prepaid Pension Costs	**---**	9.1	---
Debt Issuance Costs	**2.8**	2.6	2.6
Other Noncurrent Assets	**2.2**	2.4	3.5
Total Noncurrent Assets	**185.8**	175.6	204.9
TOTAL	**$ 474.5**	$ 444.5	$ 483.4

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) September 30, 2007	September 30, 2006	December 31, 2006
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 97.4**	$ 94.8	$ 97.8
Preferred Stock, Non-Redeemable, Non-Cumulative	**0.2**	0.2	0.2
Preferred Stock, Redeemable, Cumulative	**1.8**	1.9	1.9
Long-Term Debt, Less Current Portion	**159.8**	140.1	140.0
Total Capitalization	**259.2**	237.0	239.9
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.3	0.3
Accounts Payable	**15.0**	16.1	19.8
Short-Term Debt	**13.0**	17.6	26.0
Taxes Payable	**3.5**	1.2	0.9
Interest and Dividends Payable	**5.0**	4.5	1.6
Other Current Liabilities	**4.9**	4.8	4.8
Total Current Liabilities	**41.8**	44.5	53.4
Deferred Income Taxes	**31.4**	50.5	34.5
Noncurrent Liabilities:			
Power Supply Contract Obligations	**77.7**	97.3	92.6
Retirement Benefit Obligations	**50.8**	13.8	49.7
Environmental Obligations	**12.0**	---	12.0
Other Noncurrent Liabilities	**1.6**	1.4	1.3
Total Noncurrent Liabilities	**142.1**	112.5	155.6
TOTAL	**$ 474.5**	$ 444.5	$ 483.4

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Nine Months Ended September 30,	
	2007	2006
Operating Activities:		
Net Income	**$ 6.0**	$ 5.3
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**13.4**	12.0
Deferred Taxes	**(2.5)**	(1.2)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**(0.3)**	1.0
Accrued Revenue	**4.3**	(0.7)
Accounts Payable	**(4.8)**	(4.5)
Taxes Payable	**2.6**	1.6
All other Current Assets and Liabilities	**1.7**	0.8
Other, net	**3.2**	2.7
Cash Provided by Operating Activities	**23.6**	17.0
Investing Activities:		
Property, Plant and Equipment Additions	**(25.9)**	(24.7)
Cash (Used in) Investing Activities	**(25.9)**	(24.7)
Financing Activities:		
Repayment of Short-Term Debt, net	**(13.0)**	(1.1)
Proceeds from Issuance of Long-Term Debt	**20.0**	15.0
Repayment of Long-Term Debt	**(0.1)**	(0.3)
Dividends Paid	**(6.0)**	(5.9)
Issuance of Common Stock	**1.3**	0.8
Retirement of Preferred Stock	**(0.1)**	(0.2)
Other, net	**(0.2)**	---
Cash Provided by Financing Activities	**1.9**	8.3
Net Increase (Decrease) in Cash	**(0.4)**	0.6
Cash at Beginning of Period	**4.6**	3.2
Cash at End of Period	**$ 4.2**	$ 3.8
Supplemental Cash Flow Information:		
Interest Paid	**$ 7.6**	$ 7.0
Income Taxes Paid	**$ 3.3**	$ 2.7

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and nine months ended September 30, 2007 are not necessarily indicative of results to be expected for the year ending December 31, 2007. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2006, as filed with the SEC on February 21, 2007, for a description of the Company's Basis of Presentation.

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. (Usource) are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In February 2007, the FASB issued FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." (SFAS No. 159), effective for fiscal years beginning after November 15, 2007. SFAS No. 159 includes an amendment of FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities." SFAS No. 159 permits entities to choose, at specified election dates, to measure eligible items at fair value and requires unrealized gains and losses on items for which the fair value option has been elected to be reported in earnings. The Company does not expect SFAS No. 159 to have a material impact on the Company's Consolidated Financial Position.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109. Under FIN 48, tax positions accounted for under FAS 109 will be evaluated for recognition, derecognition, and classification. The Company adopted FIN 48 as of January 1, 2007, as required. The adoption of FIN 48 did not have a significant impact on the Company's financial position and results of operations. See Note 9.

In September 2006, the FASB issued FASB Statement No. 157, “Fair Value Measurements”, (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect SFAS No. 157 to have an impact on the Company’s Consolidated Financial Statements.

In February 2006, the FASB issued FASB Statement No. 155, “Accounting for Certain Hybrid Financial Instruments”, (SFAS No. 155), which amends SFAS No.133 and FASB Statement No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities”, (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity’s first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company’s adoption of SFAS No. 155 did not have an impact on the Company’s Consolidated Financial Statements.

Reclassifications - Certain amounts previously reported have been reclassified to conform to current year presentation. The Company reclassified retirement benefit obligations from Other Noncurrent Liabilities to Retirement Benefit Obligations on the balance sheet and certain expenses between Purchased Electricity, Purchased Gas and Operations and Maintenance Expenses for presentation purposes.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
09/13/07	11/15/07	11/01/07	$ 0.345
06/21/07	08/15/07	08/01/07	$ 0.345
03/22/07	05/15/07	05/01/07	$ 0.345
01/18/07	02/15/07	02/01/07	$ 0.345
09/29/06	11/15/06	11/01/06	$ 0.345
06/22/06	08/15/06	08/01/06	$ 0.345
03/23/06	05/15/06	05/01/06	$ 0.345
01/12/06	02/15/06	02/01/06	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first nine months of 2007, the Company sold 28,675 shares of its Common Stock, at an average price of $27.65 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $793,000 were used to reduce short-term borrowings.

During the first nine months of 2006, the Company sold 30,782 shares of its Common Stock, at an average price of $24.59 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $757,000 were used to reduce short-term borrowings.

Also, in the third quarter of 2007, the Company issued and sold 42,437 shares of its Common Stock, at a final average price of $10.70 per share, in connection with the exercise of stock options under the Unitil Corporation Key Employee Stock Option Plan (KESOP). As disclosed in Note 2 to the Company’s Form 10-K for the year ended December 31, 2006, the KESOP was a 10-year plan which began in March 1989. The number of shares underlying options granted under this plan, as well as the terms and conditions of each grant, were determined by the Key Employee Stock Option Plan Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vested upon grant. The 10-year period in which options could be granted under this plan expired in March 1999. The plan provides dividend equivalents on options granted, which are recorded at fair value as compensation expense. As of September 30, 2007, there are no options remaining under the KESOP. Net proceeds of $454,000 were used by the Company to reduce short-term borrowings.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 9, 2007, 9,020 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $230,461. Compensation expense associated with annual grants of shares issued under the Plan is recognized on a monthly basis as the shares vest and was $0.3 million and $0.3 million for the nine months ended September 30, 2007 and 2006, respectively. At September 30, 2007, there was approximately $0.8 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 2.4 years as the shares vest.

Details on preferred stock at September 30, 2007, September 30, 2006 and December 31, 2006 are shown below:

(Amounts in Millions)

	(Unaudited) September 30,		December 31,
	2007	2006	2006
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.9	0.9
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.0**	$ 2.1	$ 2.1

NOTE 4 – LONG-TERM DEBT

On May 2, 2007, Unitil Corporation issued and sold $20 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors in the form of a private placement. The proceeds from this long-term financing were used to refinance existing short-term debt and for general corporate purposes of the Company and its subsidiaries.

Details on long-term debt at September 30, 2007, September 30, 2006 and December 31, 2006 are shown below:

(Amounts in Millions)

	(Unaudited) September 30, 2007	September 30, 2006	December 31, 2006
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**$ 15.0**	$ 15.0	$ 15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Unitil Corporation:			
Senior Notes:			
6.33% Notes, Due May 1, 2022	**20.0**	---	---
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5.2**	5.4	5.3
Total	**160.2**	140.4	140.3
Less: Installments due within one year	**0.4**	0.3	0.3
Total Long-term Debt	**$ 159.8**	$ 140.1	$ 140.0

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at September 30, 2007 is estimated to be in a range of up to approximately $170 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to the duration of the contracts, which range from three months to three years. As of September 30, 2007 there are $8.3 million of guarantees outstanding and these guarantees extend through March 13, 2009. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and nine months ended September 30, 2007 and September 30, 2006 (Millions):

Three Months Ended:	Electric	Gas	Other	Non-Regulated	Total
September 30, 2007					
Revenues	**$ 56.9**	**$ 3.9**	**$ ---**	**$ 1.0**	**$ 61.8**
Segment Profit (Loss)	**2.3**	**(0.7)**	**(0.1)**	**0.1**	**1.6**
Capital Expenditures	**4.7**	**1.7**	**0.1**	**---**	**6.5**
September 30, 2006					
Revenues	$ 61.2	$ 4.4	$ ---	$ 0.6	$ 66.2
Segment Profit (Loss)	2.5	(0.8)	0.1	---	1.8
Capital Expenditures	7.0	3.3	---	---	10.3
Nine Months Ended:					
September 30, 2007					
Revenues	**$ 171.3**	**$ 24.5**	**$ ---**	**$ 2.8**	**$ 198.6**
Segment Profit (Loss)	**5.7**	**---**	**---**	**0.2**	**5.9**
Capital Expenditures	**21.8**	**3.9**	**0.4**	**---**	**26.1**
Segment Assets	**339.0**	**110.2**	**24.4**	**0.9**	**474.5**
September 30, 2006					
Revenues	$ 171.0	$ 24.4	$ ---	$ 1.8	$ 197.2
Segment Profit (Loss)	5.5	(0.5)	0.4	(0.2)	5.2
Capital Expenditures	18.6	6.0	0.1	---	24.7
Segment Assets	323.5	100.0	19.9	1.1	444.5

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2006 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 21, 2007.

FG&E – Electric Division – On December 1, 2006, FG&E submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan (the Annual Reconciliation Filing). On May 25, 2007 the MDPU approved FG&E's 2005 Annual Reconciliation Filing. On September 7, 2007, a Settlement Agreement between FG&E and the Attorney General of Massachusetts was filed resolving all disputes with regard to FG&E's 2006 Annual Reconciliation Filing. Approval of the Settlement Agreement is pending.

On August 17, 2007, FG&E filed an electric distribution rate increase of $3.3 million, which represents an increase of 4.7 percent over FG&E's 2006 total electric operating revenue. The MDPU has suspended the effective date until March 1, 2008 in order to investigate the propriety of the Company's request.

FG&E – Gas Division – On January 26, 2007, the MDPU approved a rate Settlement Agreement (Settlement) between FG&E and the Attorney General of Massachusetts for FG&E's Gas Division. Under the Settlement, FG&E increased its gas distribution rates by $1.2 million on February 1, 2007, and an additional $1.0 million increase will occur on November 1, 2007. The Settlement also includes agreement on several other rate matters and service quality performance measures for the company's Gas Division in the areas of safety, customer service and satisfaction.

On September 7, 2006, the MDPU issued an order allowing FG&E to recover the costs of its actual gas and electric supply-related bad debt effective December 1, 2005. Prior to this final approval, FG&E had recovered supply-related bad debt costs based on a fixed rate formula that produced a significant under-recovery of these costs. On September 27, 2006, the Attorney General filed a Petition for Appeal with the Massachusetts Supreme Judicial Court seeking to set aside the MDPU's order. FG&E intends to support the MDPU's order but the Company cannot predict the outcome of the Attorney General's appeal at this time.

FG&E – Other – On June 22, 2007, the MDPU opened an investigation to review ratemaking practices for gas and electric utility distribution companies in Massachusetts, and consider whether existing mechanisms may be changed to better align utility companies' financial interests with the need to capture end use efficiencies and foster the advancement of price responsive demand in the wholesale energy market. This matter remains pending.

UES – On March 16, 2007, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2007, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. On April 30, 2007 the NHPUC approved UES' filing subject to adjustment and reconciliation depending on the Staff audit and Staff's on-going review with regard to the method for calculating unbilled revenues. No exceptions were noted in the final audit report, which was issued on July 11, 2007.

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement (Agreement) resolving its electric distribution base rate case filed in November, 2005. The terms of the Agreement provide for an increase in base distribution rates of $2.3 million effective as of January 1, 2006. Additionally, the Agreement authorizes two step increases in base distribution rates, related to utility plant additions in 2006, of approximately $0.4 million and $0.1 million annually, effective as of November 1, 2006 and May 1, 2007, respectively. Also, the Agreement provides for the recovery of approximately $0.3 million annually of supply-related operating and administrative costs through default energy service rates and a reduction of approximately $0.6 million in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives. The stipulated rate of return under the settlement is 8.70%, including a return on equity of 9.67%. The Agreement also authorized a temporary rate surcharge for recovery of certain rate case expenses and recoupment of the authorized distribution rate increase from January through October 2006. On August 30, 2007, UES filed a reconciliation of the surcharge, which is expected to expire effective November 1, 2007.

On June 22, 2007, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. This order sets the framework for implementation of time based rates for utility provided default service, though a number of technical issues remain to be resolved. Under the order, UES is required to file draft tariffs to provide for fixed, time-based pricing of default service for all customer classes no later than November 30, 2007. On August 31, 2007, the NHPUC issued an order on motion for rehearing, staying the June 22, 2007 order pending hearing and reconsideration of the issues. This matter remains pending.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting, for electric utilities, appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. The matter remains pending.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2006 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 21, 2007.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of September 30, 2007, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at September 30, 2007 in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts. A corresponding regulatory asset was recorded to reflect the future rate recovery of these costs. As noted above, please refer to Note 5 to the financial statements in Item 8 of Part II of the Company's Form 10-K for December 31, 2006 for additional information.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit pension plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

In September 2006, the FASB issued SFAS No. 158 which requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

Pension Plan – The Company's defined benefit pension plan covers substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.

FG&E recovers the costs associated with its pension and PBOP costs on an annually reconciling basis through a rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF). FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106 and amortizes increases and/or decreases in that deferral balance into the PAF for recovery over a three year period.

UES recovers its pension and PBOP expenses in base rates and amortizes deferred pension costs as these costs are recovered over a six year period in base rates.

The following tables show the components of net periodic pension cost, (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Components of NPPC (000's)				
Service Cost	**$ 492**	$ 450	**$ 1,476**	$ 1,350
Interest Cost	**834**	788	**2,502**	2,365
Expected Return on Plan Assets	**(1,050)**	(944)	**(3,146)**	(2,831)
Amortization of Prior Service Cost	**27**	27	**80**	80
Amortization of Net Loss	**336**	331	**1,008**	993
Subtotal NPPC	**639**	652	**1,920**	1,957
Amounts Capitalized and Deferred	**(215)**	(127)	**(651)**	(772)
NPPC Recognized	**$ 424**	$ 525	**$ 1,269**	$ 1,185

Key Assumptions (Weighted Average)	**2007**	2006
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Used to Determine NPPC:		
Discount Rate	**5.50%**	5.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%
Rate of Compensation Increase	**3.50%**	3.50%

Employer Contributions – On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. As of September 30, 2007, the Company has made contributions of $2.8 million to the Plan in 2007 and does not anticipate making any additional contributions in 2007. The Company contributed $2.5 million in 2006.

PBOP Plan - The Company sponsors the PBOP Plan, primarily to provide health care and life insurance benefits to employees and retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Components of NPPBC (000's)				
Service Cost	**$ 358**	$ 321	**$ 1,073**	$ 962
Interest Cost	**514**	507	**1,543**	1,522
Expected Return on Plan Assets	**(61)**	(49)	**(184)**	(146)
Amortization of Prior Service Cost	**341**	340	**1,020**	1,020
Amortization of Transition (Asset) Obligation	**5**	5	**16**	16
Amortization of Net (Gain) Loss	**17**	40	**52**	120
Subtotal NPPBC	**1,174**	1,164	**3,520**	3,494
Amounts Capitalized and Deferred	**(489)**	(559)	**(1,506)**	(1,673)
NPPBC Recognized	**$ 685**	$ 605	**$ 2,014**	$ 1,821

Weighted-Average Assumptions	2007	2006
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	5.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2016
Used to Determine NPPBC:		
Discount Rate	**5.50%**	5.50%
Expected Long-Term Rate of Return on Plan Assets	**8.50%/5.50%** [1]	8.50%/5.50% [1]
Health Care Cost Trend Rate Assumed for Next Year	**9.00%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2016

(1) Funding of the PBOP Plan is made into two VEBT's; one is a union VEBT and the other is a non-union VEBT. The expected long-term rate of return on plan assets for the union VEBT is 8.50%. The non-union VEBT is subject to income taxes and therefore the expected long-term rate of return on plan assets is 5.50%, reflecting the effect of taxes.

Employer Contributions – As of September 30, 2007, the Company had made $1.7 million of contributions to the PBOP Plan in 2007. The Company presently anticipates contributing an additional $0.8 million to fund the Plan in 2007 for an estimated funding total of $2.5 million in the year. The Company contributed $2.2 million in 2006.

SERP - The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors.

The components of net periodic SERP cost are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Components of NPSC (000's)				
Service Cost	**$ 40**	$ 36	**$ 122**	$ 110
Interest Cost	**29**	26	**88**	78
Amortization of Transition Obligation	**---**	4	**---**	13
Amortization of Prior Service Cost	**---**	---	**(1)**	(1)
Amortization of Net Loss	**11**	10	**33**	29
Net Periodic SERP Cost	**$ 80**	$ 76	**$ 242**	$ 229

Employer Contributions – As of September 30, 2007, the Company has made payments of $54,000 to beneficiaries. The Company presently anticipates making additional benefit payments of $18,000 in 2007 for a total of $72,000.

NOTE 9: INCOME TAXES

The Company evaluated its tax positions at December 31, 2006 and for the current interim reporting period ended September 30, 2007 in accordance with FIN 48, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2004; December 31, 2005; and December 31, 2006. Income tax filings for the year ended December 31, 2006 were filed on or before September 17, 2007. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no interest and penalties recognized in the statement of earnings or accrued on the balance sheet.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2006 as filed with the Securities and Exchange Commission on February 21, 2007.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended September 30, 2007.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
7/1/07 – 7/31/07	---	---	---	n/a
8/1/07 – 8/31/07	---	---	---	n/a
9/1/07 – 9/30/07	---	---	---	n/a
Total	---	---	---	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases. The Company expects to continue with these purchases indefinitely.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated October 25, 2007 Announcing Earnings For the Quarter Ended September 30, 2007	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: October 26, 2007

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: October 26, 2007

/s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Net Income	**$ 1.6**	$ 1.8	**$ 6.0**	$ 5.3
Less: Dividend Requirements on Preferred Stock	**---**	---	**0.1**	0.1
Net Income Applicable to Common Stock	**$ 1.6**	$ 1.8	**$ 5.9**	$ 5.2
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**5,659**	5,605	**5,643**	5,592
Dilutive Effect of Stock Options and Restricted Stock (000's)	**9**	14	**16**	14
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**5,668**	5,619	**5,659**	5,606
Earnings Per Share – Basic	**$0.28**	$0.32	**$1.04**	$0.93
Earnings Per Share – Diluted	**$0.28**	$0.32	**$1.04**	$0.93

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2007

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2007

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2007

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending September 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	October 26, 2007
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	October 26, 2007
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	October 26, 2007

Exhibit 99.1

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports Third Quarter Earnings

Hampton, NH – October 25, 2007: Unitil Corporation (AMEX: UTL) (www.unitil.com) today announced net income of $1.6 million for the third quarter of 2007. Earnings per common share (EPS) were $0.28 for the three months ended September 30, 2007 compared with $0.32 in the third quarter of 2006. Earnings for the third quarter of 2007 reflect higher depreciation and interest expenses, partially offset by higher electric and gas utility sales margins and improved profits from Usource™, Unitil's non-regulated energy-brokering business. For the nine months ended September 30, EPS were $1.04 for 2007 compared to $0.93 for 2006, an increase of $0.11 per share, or 12%.

The following table presents the significant items (discussed below) contributing to the change in earnings per share in the three and nine month periods ended September 30, 2007:

2007 Earnings Per Share vs. 2006

	Period Ended September 30,			
	QTD		YTD	
2006	**$**	**0.32**	**$**	**0.93**
Electric Sales Margin		0.03		0.07
Gas Sales Margin		0.02		0.16
Usource™ Sales Margin		0.04		0.10
Operation & Maintenance Expense		---		0.02
Depreciation, Amortization & Other		(0.09)		(0.14)
Interest Expense, Net		(0.04)		(0.10)
2007	**$**	**0.28**	**$**	**1.04**

Total electric kilowatt (kWh) sales decreased 3.9% and 1.4% in the three and nine month periods ended September 30, 2007, respectively compared to the same periods in 2006. The lower kWh sales in 2007 compared to 2006 were primarily driven by cooler summer weather this year and energy conservation by our residential and commercial and industrial (C&I) customers.

Natural gas sales in the three and nine month periods ended September 30, 2007 increased 6.1% and 8.0%, respectively, compared to the same periods in 2006. The increase in gas sales in 2007 reflects a colder winter heating season this year and higher natural gas sales to C&I customers.

Selected Financial Data for 2007 is presented in the following table:

(Unaudited)

Unitil Corporation – Condensed Financial Data

(Millions, except Per Share data)

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2007	**2006**	**Change**	**2007**	**2006**	**Change**
Electric kWh Sales:						
Residential	179.7	188.6	(4.7%)	515.6	521.5	(1.1%)
Commercial/Industrial	285.1	294.9	(3.3%)	813.2	825.5	(1.5%)
Total	**464.8**	**483.5**	**(3.9%)**	**1,328.8**	**1,347.0**	**(1.4%)**
Gas Therm Sales:						
Residential	0.7	0.7	---	7.9	7.7	2.6%
Commercial/Industrial	2.8	2.6	7.7%	13.8	12.4	11.3%
Total	**3.5**	**3.3**	**6.1%**	**21.7**	**20.1**	**8.0%**
Electric Revenues	$ 56.9	$ 61.2	$ (4.3)	$ 171.3	$ 171.0	$ 0.3
Purchased Electricity	42.7	47.3	(4.6)	129.2	129.6	(0.4)
Electric Sales Margin	**14.2**	**13.9**	**0.3**	**42.1**	**41.4**	**0.7**
Gas Revenues	3.9	4.4	(0.5)	24.5	24.4	0.1
Purchased Gas	2.1	2.8	(0.7)	15.9	17.4	(1.5)
Gas Sales Margin	**1.8**	**1.6**	**0.2**	**8.6**	**7.0**	**1.6**
Usource Sales Margin	**1.0**	**0.6**	**0.4**	**2.8**	**1.8**	**1.0**
Total Sales Margin:	**17.0**	**16.1**	**0.9**	**53.5**	**50.2**	**3.3**
Operation & Maintenance Expenses	6.5	6.5	---	19.8	20.0	(0.2)
Depreciation, Amortization & Other	6.6	5.9	0.7	21.0	19.2	1.8
Interest Expense, Net	2.3	1.9	0.4	6.8	5.8	1.0
Net Income:	**$ 1.6**	**$ 1.8**	**$ (0.2)**	**$ 5.9**	**$ 5.2**	**$ 0.7**
Earnings Per Share	**$ 0.28**	**$ 0.32**	**$ (0.04)**	**$ 1.04**	**$ 0.93**	**$ 0.11**

Electric sales margin increased $0.3 million and $0.7 million in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006. The improvement in electric sales margin primarily reflects additional step rate increases approved and implemented in the last half of 2006 and the first half of 2007 in New Hampshire, partially offset by lower electric kWh sales volumes.

Natural gas sales margin increased $0.2 million and $1.6 million in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006 primarily reflecting higher sales to C&I customers and new natural gas distribution rates approved and implemented in early 2007.

Usource™ achieved increased revenues of $0.4 million and $1.0 million in the three and nine month periods ended September 30, 2007, increases of 67% and 56% respectively, over the comparable 2006 periods.

Total O&M expenses were flat for the three month period ended September 30, 2007 compared to the same period in 2006. For the nine month period ended September 30, 2007, total O&M expenses decreased $0.2 million compared to the same period in 2006. This decrease primarily reflects lower utility operating expenses which were partially offset by higher compensation and benefit costs.

Depreciation, Amortization, Taxes & Other expenses increased $0.7 million and $1.8 million in the three and nine month periods ended September 30, 2007 compared to the same periods in 2006 reflecting higher depreciation on utility plant and income taxes on higher levels of pre-tax earnings in 2007 compared to 2006.

Interest Expense, Net increased $0.4 million and $1.0 million in the three and nine month periods ended September 30, 2007 compared to the same periods in 2006 reflecting higher debt outstanding and higher interest rates.

Also in the third quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

About Unitil

Unitil is a public utility holding company with subsidiaries providing electric service in New Hampshire and electric and gas service in Massachusetts and energy services throughout the Northeast. Its subsidiaries include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Unitil Power Corp., Unitil Realty Corp., Unitil Service Corp. and its non-regulated business segment Unitil Resources, Inc. Usource L.L.C. is a subsidiary of Unitil Resources, Inc. Usource™ is a registered trademark of Unitil Resources, Inc.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended March 31, 2008

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer___ Accelerated filer X

Non-accelerated filer___ (Do not check if a smaller reporting company) Smaller reporting company___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No X

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 23, 2008
Common Stock, No par value	5,765,031 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended March 31, 2008

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through two utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with an operating franchise in the southeastern seacoast and capital city areas of New Hampshire. FG&E is a combination gas and electric utility with an operating franchise in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 99,400 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are pure distribution utilities with a combined investment in net utility plant of $249.4 million at March 31, 2008. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource™ (Usource) subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

On February 15, 2008, the Company entered into a Stock Purchase Agreement (Agreement) with NiSource Inc. (NiSource) and Bay Sate Gas Company (Bay State, which is a wholly owned utility subsidiary of NiSource), to acquire all of the outstanding stock of Northern Utilities, Inc. (Northern), and Granite State Gas Transmission, Inc. (Granite) for $160 million plus a net working capital adjustment. Northern's principal business is the retail distribution of natural gas to approximately 53,000 customers located in 44 coastal New Hampshire and southern Maine communities. Portions of Northern's natural gas service territory are contiguous and overlapping with Unitil's electric distribution service territory in New Hampshire. Granite's principal business is a natural gas transmission company, principally engaged in the business of rendering natural gas transportation services to Northern.

Consummation of the acquisition is subject to various closing conditions, including but not limited to the receipt of requisite regulatory approvals from certain federal and state public utility, antitrust and other regulatory authorities. It is currently anticipated that the acquisition will be consummated in the fourth quarter of 2008. However, no assurance can be given that the acquisition will occur, or, the timing of its completion.

RATES AND REGULATION

Unitil's utility operations related to wholesale and interstate business activities are regulated by the Federal Energy Regulatory Commission (FERC). The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Public Utilities (MDPU), formerly the Massachusetts Department of Telecommunications and Energy, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets.

As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities provide for the delivery of that supply of electricity over their distribution systems at regulated rates. Both UES and FG&E

continue to provide basic or default electric supply service to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' future performance under multi-year energy brokering contracts.
- Risks associated with the acquisition of Northern and Granite, discussed above include:
    - Successful integration of the acquired business into the Company;
    - Receipt of regulatory approval of the transaction;
    - Ability to finance transaction at reasonable terms; and
    - Acquisition costs expended for banker fees, legal fees and other acquisition related expenses would adversely affect the Company's financial condition if the acquisition is not completed;

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2007 as filed with the Securities and Exchange Commission on February 12, 2008, other than the risks disclosed above associated with the acquisition of Northern and Granite.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended March 31, 2008 and March 31, 2007 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 1 of this report.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $3.3 million for the first quarter of 2008. Earnings per common share (EPS) were $0.57 for the three months ended March 31, 2008, an improvement of $0.11 per share or 24% over the first quarter of 2007.

Unitil's improved first quarter earnings in 2008 over 2007 were driven by higher gas sales margin and lower operating expenses, including the benefit from the proceeds of an insurance settlement associated with environmental remediation costs. These favorable factors were partially offset by higher amortization expenses and higher interest expense in the current year.

The following table presents the significant items contributing to the improvement in earnings per share in the first quarter of 2008 compared to the same period in 2007:

	Earnings Per Share
Three Months Ended March 31, 2007:	**$ 0.46**
Electric Sales Margin	(0.04)
Gas Sales Margin	0.10
Usource Sales Margin	0.01
Operation & Maintenance Expense	0.19
Depreciation, Amortization, Taxes & Other	(0.10)
Interest Expense, net	(0.05)
Three Months Ended March 31, 2008:	**$ 0.57**

In the first quarter of 2008, Unitil's electric kilowatt (kWh) sales decreased 1.4% compared to the same period in 2007. Gas sales in the first quarter of 2008 decreased 1.7% compared to the same period in 2007. The lower unit sales in 2008 compared to 2007 were driven by milder winter weather this year and lower average usage by our customers reflecting a slowing economy and energy conservation.

Electric sales margin was lower by $0.4 million in the three months ended March 31, 2008 compared to the same period in 2007 due to lower electric kWh sales volumes, partially offset by higher electric base rates. Gas sales margin increased $0.9 million in the three months ended March 31, 2008 compared to the same period in 2007 reflecting higher gas base rates, implemented in 2007. Usource, our non-regulated energy brokering business, recorded increased sales margin of $0.1 million in the first quarter of 2008, an increase of 11% over the first quarter of 2007.

Total Operation & Maintenance (O&M) expenses decreased $1.8 million for the three month period ended March 31, 2008 compared to the same period in 2007. This decrease reflects a reduction to operating expenses of $2.8 million from the proceeds of an insurance settlement associated with environmental remediation costs. This reduction to operating expenses was partially offset by annual increases in salary, wage and benefit costs of $0.7 million, higher professional fees of $0.2 million and higher bad debt expenses of $0.1 million.

Depreciation, Amortization, Taxes & Other expenses increased $1.2 million in the three month period ended March 31, 2008 compared to the same period in 2007 primarily reflecting the amortization of $0.7 million of natural gas inventory carrying costs and higher income taxes on higher levels of pre-tax earnings in 2008 compared to 2007.

Interest Expense, Net increased $0.5 million in the three month period ended March 31, 2008 compared to the same period in 2007 primarily reflecting higher debt outstanding.

In 2007, Unitil's annual common dividend was $1.38, representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock. At its January, 2008 and March, 2008 meetings, the Unitil Board of Directors declared quarterly dividends on the Company's common stock of $0.345 per share.

A more detailed discussion of the Company's results of operations for the three months ended March 31, 2008 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

The Company's investment in Net Utility Plant increased by $11.7 million as of March 31, 2008 compared to March 31, 2007. This increase was due to capital expenditures related to UES' and FG&E's electric and gas distribution systems, including expenditures of approximately $1.0 million for the Company's Advanced Metering Infrastructure (AMI) project.

Regulatory Assets decreased $29.0 million as of March 31, 2008 compared to March 31, 2007, primarily reflecting current year cost recoveries. A significant portion of this decrease is matched by a corresponding decrease of $19.9 million in Power Supply Contract Obligations. The remaining decrease primarily reflects lower levels of Regulatory Assets associated with deferred taxes and retirement benefit obligations as well as recoveries of deferred charges.

Long-Term Debt increased $19.6 million as of March 31, 2008 compared to March 31, 2007, reflecting the issuance and sale on May 2, 2007 by Unitil Corporation of $20.0 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors in the form of a private placement. Short-term Debt decreased $13.0 million as of March 31, 2008 compared to March 31, 2007, as short-term borrowings were refinanced with the issuance of Senior Long-Term Notes, discussed above.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – In the first quarter of 2008, Unitil's total electric kWh sales decreased 1.4% compared to the first quarter of 2007. Sales to residential and C&I customers decreased 0.9% and 1.7%, respectively, in the first quarter of 2008 compared to the same period in 2007. The lower kWh sales in 2008 compared to 2007 were primarily driven by lower average usage by our customers reflecting a slowing economy and energy conservation.

The following table details total kWh sales for the three months ended March 31, 2008 and 2007 by major customer class:

kWh Sales (millions)

	Three Months Ended March 31,			
	2008	2007	Change	% Change
Residential	**182.4**	184.0	(1.6)	(0.9%)
Commercial/Industrial	**261.1**	265.6	(4.5)	(1.7%)
Total	**443.5**	449.6	(6.1)	(1.4%)

Electric Operating Revenues and Sales Margin - The following table details total Electric Operating Revenues and Sales Margin for the three months ended March 31, 2008 and 2007:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended March 31,			
	2008	2007	$ Change	% Change[1]
Electric Operating Revenue:				
Residential	**$ 30.3**	$ 32.8	$ (2.5)	(4.0%)
Commercial / Industrial	**26.3**	29.9	(3.6)	(5.7%)
Total Electric Operating Revenue	**$ 56.6**	$ 62.7	$ (6.1)	(9.7%)
Cost of Electric Sales:				
Purchased Electricity	**$ 42.9**	$ 48.2	$ (5.3)	(8.5%)
Conservation & Load Management	**0.6**	1.0	(0.4)	(0.6%)
Electric Sales Margin	**$ 13.1**	$ 13.5	$ (0.4)	(0.6%)

(1) Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues decreased by $6.1 million, or 9.7%, in the three months ended March 31, 2008 compared to the same period in 2007. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The decrease in Total Electric Operating Revenues in the three months ended March 31, 2008 reflects lower Purchased Electricity costs of $5.3 million, lower C&LM revenues of $0.4 million and lower sales margin of $0.4 million.

Purchased Electricity and C&LM revenues decreased a combined $5.7 million, or 9.1%, of Total Electric Operating Revenues in the three months ended March 31, 2008 compared to the same period in 2007, reflecting lower electric kWh sales, an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity prices. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin was lower by $0.4 million in the three months ended March 31, 2008 compared to the same period in 2007 due to lower electric kWh sales volumes, partially offset by higher electric base rates.

Gas Sales, Revenues and Margin

Therm Sales – Therm sales of natural gas decreased 1.7% in the three months ended March 31, 2008 compared to the same period in 2007. Sales to residential customers and C&I customers decreased 2.0% and 1.4%, respectively, in the first quarter of 2008 compared to the same period in 2007. The decrease in gas sales in 2008 reflects a milder winter heating season this year and lower average usage by our customers reflecting a slowing economy and energy conservation.

The following table details total firm therm sales for the three months ended March 31, 2008 and 2007, by major customer class:

Therm Sales (millions)

	Three Months Ended March 31,			
	2008	2007	Change	% Change
Residential	**4.8**	4.9	(0.1)	(2.0%)
Commercial/Industrial	**6.8**	6.9	(0.1)	(1.4%)
Total	**11.6**	11.8	(0.2)	(1.7%)

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three months ended March 31, 2008 and 2007:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended March 31,			
	2008	2007	$ Change	% Change[1]
Gas Operating Revenue:				
Residential	**$ 8.0**	$ 8.1	$ (0.1)	(0.7%)
Commercial / Industrial	**6.3**	6.1	0.2	1.4%
Total Gas Operating Revenue	**$ 14.3**	$ 14.2	$ 0.1	0.7%
Cost of Gas Sales:				
Purchased Gas	**$ 9.0**	$ 9.8	$ (0.8)	(5.6%)
Conservation & Load Management	**---**	---	---	---
Gas Sales Margin	**$ 5.3**	$ 4.4	$ 0.9	6.3%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $0.1 million, or 0.7%, in the three months ended March 31, 2008 compared to the same period in 2007. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in three months ended March 31, 2008 reflects higher sales margin of $0.9 million, offset by lower Purchased Gas costs of $0.8 million.

Purchased Gas and C&LM revenues decreased a combined $0.8 million, or 5.6%, of Total Gas Operating Revenues in three months ended March 31, 2008 compared to the same period in 2007, primarily reflecting lower natural gas sales and an increase in the amount of natural gas purchased by customers directly from third-party suppliers. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin increased $0.9 million in the three months ended March 31, 2008 compared to the same period in 2007 reflecting higher gas base rates, implemented in 2007.

Operating Revenue - Other

The following table details total Other Operating Revenue for the three months ended March 31, 2008 and 2007:

Other Operating Revenue (Millions)

	Three Months Ended March 31,			
	2008	2007	$ Change	% Change
Other	**$ 1.0**	$ 0.9	$ 0.1	11.1%
Total Other Operating Revenue	**$ 1.0**	$ 0.9	$ 0.1	11.1%

Total Other Operating Revenue increased $0.1 million, or 11.1%, in the three month period ended March 31, 2008 compared to the same period in 2007. The increase was the result of growth in revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity decreased $5.3 million, or 11.0%, in the three month period ended March 31, 2008 compared to the same period in 2007, reflecting lower electric kWh sales, an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $0.8 million, or 8.2%, in the three month period ended March 31, 2008 compared to the same period in 2007, primarily reflecting lower natural gas sales and an increase in the amount of natural gas purchased by customers directly from third-party suppliers. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) - O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expenses decreased $1.8 million for the three month period ended March 31, 2008 compared to the same period in 2007. This decrease reflects a reduction to operating expenses of $2.8 million from the proceeds of an insurance settlement associated with environmental remediation costs. This reduction to operating expenses was partially offset by annual increases in salary, wage and benefit costs of $0.7 million, higher professional fees of $0.2 million and higher bad debt expenses of $0.1 million.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use electricity and natural gas more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased by $0.4 million, or 40.0%, in three month period ended March 31, 2008 compared to the same period in 2007. The decrease reflects the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense increased $0.7 million, or 15.6%, for the three month period ended March 31, 2008 compared to the same period in 2007. This increase primarily reflects the amortization of $0.7 million of natural gas inventory carrying costs deferred under a previous regulatory ruling.

Local Property and Other Taxes - Local Property and Other Taxes increased by $0.2 million, or 13.3% for the three month period ended March 31, 2008 compared to the same period in 2007. This increase was due to higher property tax rates on increased property assessments and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes - Federal and State Income Taxes were higher by $0.2 million for the three months ended March 31, 2008 compared to the same period in 2007 reflecting higher pre-tax earnings.

Other Non-Operating Expense

Other Non-Operating Expense increased by $0.1 million in the three month period ended March 31, 2008 compared to the same period in 2007. This increase reflects an adjustment of $0.1 million in conjunction with the Company's recently approved electric base distribution rate increase in Massachusetts.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (millions)	**Three Months Ended March 31,**		
	2008	2007	Change
Interest Expense			
Long-term Debt	**$ 2.9**	$ 2.6	$ 0.3
Short-term Debt	**0.2**	0.4	(0.2)
Regulatory Liabilities	**---**	---	---
Subtotal Interest Expense	**3.1**	3.0	0.1
Interest Income			
Regulatory Assets	**(0.6)**	(0.8)	0.2
AFUDC and Other	**0.1**	(0.1)	0.2
Subtotal Interest Income	**(0.5)**	(0.9)	0.4
Total Interest Expense, Net	**$ 2.6**	$ 2.1	$ 0.5

Interest Expense, Net increased by $0.5 million in the three month period ended March 31, 2008 compared to the same period in 2007. Interest expense on long-term borrowings increased due to the issuance of new long-term debt by Unitil on May 2, 2007. Unitil issued and sold $20 million of Senior Long-Term Notes at a coupon rate of 6.33%, through a private placement to institutional investors. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries. The resulting reduction in average daily short-term bank borrowings lowered short-term interest expense for the first quarter of 2008 compared to the same period in 2007. An adjustment of $0.2 million related to earnings on funds used for capital projects ordered in conjunction with the Company's recently approved electric base distribution rate increase in Massachusetts and lower carrying charges earned on regulatory assets also contributed to the increase in Interest Expense, Net.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. The Company had short-term debt outstanding through bank borrowings of $16.7 and $29.7 at March 31, 2008 and March 31, 2007, respectively. In addition, Unitil had approximately $4.0 million in cash at March 31, 2008. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

On February 15, 2008, the Company entered into a Stock Purchase Agreement with NiSource and Bay State to acquire all of the outstanding stock of Northern Utilities, Inc. and Granite State Gas Transmission, Inc. The Company has entered into a senior unsecured bridge facility, which is available to finance this transaction. The Company anticipates either financing the initial acquisition or refinancing the bridge facility with the issuance of a combination of unsecured senior notes and common/or preferred equity securities.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to the duration of the contracts, which range from less than one month to two and one-half years. As of March 31, 2008, there were approximately $6.0 million of guarantees outstanding and the longest term guarantee extends through October 31, 2009.

The tables below summarize the major sources and uses of cash (in millions) for the three months ended March 31, 2008, compared to the same period in 2007.

Cash Provided by Operating Activities	**$ 7.9**	$ 6.1

Cash Provided by Operating Activities - Cash Provided by Operating Activities was $7.9 million during the first three months ended March 31, 2008, an increase of $1.8 million over the comparable period in 2007. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes of $1.0 million, was $1.7 million higher in the first three months of 2008 compared to 2007. Working Capital related cash flows increased by $0.6 million during the first three months of 2008 compared to the same period in 2007. Deferred Restructuring Charges were a $1.0 million source of cash in the first quarter of 2008 compared to the same period in 2007. These charges were deferred in prior periods for collection current rates. All other changes in operating activities were a net $1.5 million in uses of cash in the first three months of 2008 compared to 2007, including a $2.8 million source of cash from the insurance settlement discussed above.

Cash (Used in) Investing Activities	**$ (4.5)**	$ (9.6)

Cash (Used in) Investing Activities - Cash (Used in) Investing Activities was $4.5 million for the three months ended March 31, 2008 reflecting a source of cash due to a decrease in capital spending of $5.1 million over the comparable period in 2007 mainly due to the completion of the Company's Advanced Metering Infrastructure ("AMI") project. In the first quarter 2007, capital expenditures included approximately $2.8 million of cash outlays for investment in the AMI project. Capital expenditure projections are subject to changes during the fiscal year.

Cash Provided by (Used in) Financing Activities	**$ (4.0)**	$ 1.7

Cash Provided by (Used in) Financing Activities - Cash Used in Financing Activities was $4.0 million in the three months ended March 31, 2008, a decrease of $5.7 million over the comparable period in 2007. Cash provided from short-term debt declined by $5.8 million in the first quarter of 2008, principally reflecting the repayment of short-term debt from the proceeds of an insurance settlement. All other cash flows provided from other financing activities aggregated to a net $0.1 million increase in the first three months of 2008 as compared to the same period in 2007.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 12, 2008.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDPU and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided below. The Company receives a return on investment on its regulated assets for which a cash outflow has been made.

Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDPU and NHPUC.

Regulatory Assets consist of the following (millions)	March 31, 2008	March 31, 2007	December 31, 2007
Power Supply Buyout Obligations	**$ 67.7**	$ 87.6	$ 72.7
Deferred Restructuring Costs	**29.6**	30.9	30.5
Generation-related Assets	**1.4**	2.1	1.6
Subtotal – Restructuring Related Items	**98.7**	120.6	104.8
Retirement Benefit Obligations	**35.1**	37.1	35.1
Income Taxes	**14.2**	18.7	14.6
Environmental Obligations	**13.3**	13.0	13.1
Other	**3.0**	3.9	2.9
Total Regulatory Assets	**$ 164.3**	$ 193.3	$ 170.5

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations - The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company

sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans”, (SFAS No. 158), an amendment of SFAS No. 87, “Employers’ Accounting for Pensions”, SFAS No. 88, “Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits,” SFAS No. 106, “Employers’ Accounting for Postretirement Benefits other than Pensions” and SFAS No. 132(R), “Employers’ Disclosures about Pensions and Other Postretirement Benefits.” SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

The Company’s reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company’s health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The Company’s RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. The Company’s RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company’s RBO.

If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2007 and 2006, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2007 and 2006, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $690,000 and $683,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $539,000 and $530,000, respectively. (See Note 8)

Income Taxes - Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company’s current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company’s consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, “Accounting for Income Taxes” (SFAS No. 109) and under FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48), an interpretation of FAS 109.

Depreciation - Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company’s fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies - The Company’s accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of March 31, 2008, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company’s consolidated financial statements below.

Refer to “Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company's debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company's short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company's interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company's short-term borrowings for the three months ended March 31, 2008 and March 31, 2007 were 3.84% and 5.77%, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions, except common shares and per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2008	2007
Operating Revenues		
Electric	**$ 56.6**	$ 62.7
Gas	**14.3**	14.2
Other	**1.0**	0.9
Total Operating Revenues	**71.9**	77.8
Operating Expenses		
Purchased Electricity	**42.9**	48.2
Purchased Gas	**9.0**	9.8
Operation and Maintenance	**4.7**	6.5
Conservation & Load Management	**0.6**	1.0
Depreciation and Amortization	**5.2**	4.5
Provisions for Taxes:		
Local Property and Other	**1.7**	1.5
Federal and State Income	**1.8**	1.6
Total Operating Expenses	**65.9**	73.1
Operating Income	**6.0**	4.7
Other Non-Operating Expense	**0.1**	---
Income Before Interest Expense	**5.9**	4.7
Interest Expense, Net	**2.6**	2.1
Net Income	**3.3**	2.6
Less: Dividends on Preferred Stock	**---**	---
Earnings Applicable to Common Shareholders	**$ 3.3**	$ 2.6
Average Common Shares Outstanding – Basic (000's)	**5,719**	5,627
Average Common Shares Outstanding – Diluted (000's)	**5,724**	5,644
Earnings Per Common Share (Basic and Diluted)	**$ 0.57**	$ 0.46
Dividends Declared Per Share of Common Stock	**$ 0.69**	$ 0.69

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) March 31, 2008	March 31, 2007	December 31, 2007
ASSETS:			
Utility Plant:			
Electric	**$ 271.3**	$ 255.3	$ 266.2
Gas	**69.2**	63.9	67.8
Common	**27.2**	25.3	26.2
Construction Work in Progress	**4.9**	17.2	20.3
Total Utility Plant	**372.6**	361.7	380.5
Less: Accumulated Depreciation	**123.2**	124.0	131.6
Net Utility Plant	**249.4**	237.7	248.9
Current Assets:			
Cash	**4.0**	2.8	4.6
Accounts Receivable – Net of Allowance for Doubtful Accounts of $1.4, $2.0 and $1.3	**28.9**	28.4	24.9
Accrued Revenue	**14.0**	12.0	12.7
Refundable Taxes	**---**	---	0.7
Materials and Supplies	**2.5**	2.5	4.5
Prepayments and Other	**1.2**	1.1	1.5
Total Current Assets	**50.6**	46.8	48.9
Noncurrent Assets:			
Regulatory Assets	**164.3**	193.3	170.5
Debt Issuance Costs, net	**2.8**	2.5	2.8
Other Noncurrent Assets	**2.2**	2.8	3.5
Total Noncurrent Assets	**169.3**	198.6	176.8
TOTAL	**$ 469.3**	$ 483.1	$ 474.6

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) March 31, 2008	March 31, 2007	December 31, 2007
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 100.0**	$ 96.8	$ 100.4
Preferred Stock, Non-Redeemable, Non-Cumulative	**0.2**	0.2	0.2
Preferred Stock, Redeemable, Cumulative	**1.9**	1.9	1.9
Long-Term Debt, Less Current Portion	**159.6**	140.0	159.6
Total Capitalization	**261.7**	238.9	262.1
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.3	0.4
Capitalized Leases, Current Portion	**0.3**	0.2	0.3
Short-Term Debt	**16.7**	29.7	18.8
Accounts Payable	**15.6**	17.9	17.6
Taxes Payable	**2.2**	2.1	---
Interest and Dividends Payable	**5.0**	4.5	1.9
Other Current Liabilities	**4.4**	3.9	5.1
Total Current Liabilities	**44.6**	58.6	44.1
Deferred Income Taxes	**31.9**	33.8	33.4
Noncurrent Liabilities:			
Power Supply Contract Obligations	**67.7**	87.6	72.7
Retirement Benefit Obligations	**49.6**	51.0	48.2
Environmental Obligations	**12.0**	12.0	12.0
Capitalized Leases, Less Current Portion	**0.4**	0.1	0.5
Other Noncurrent Liabilities	**1.4**	1.1	1.6
Total Noncurrent Liabilities	**131.1**	151.8	135.0
TOTAL	**$ 469.3**	$ 483.1	$ 474.6

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Three Months Ended March 31,	
	2008	2007
Operating Activities:		
Net Income	**$ 3.3**	$ 2.6
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**5.2**	4.5
Deferred Taxes	**(0.2)**	(0.5)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**(4.0)**	(5.9)
Accrued Revenue	**(1.3)**	1.8
Accounts Payable	**(2.0)**	(1.9)
Taxes Payable	**2.9**	1.2
All other Current Assets and Liabilities	**2.6**	2.4
Deferred Restructuring Charges	**1.0**	---
Other, net	**0.4**	1.9
Cash Provided by Operating Activities	**7.9**	6.1
Investing Activities:		
Property, Plant and Equipment Additions	**(4.5)**	(9.6)
Cash (Used in) Investing Activities	**(4.5)**	(9.6)
Financing Activities:		
Proceeds from (Repayment of) Short-Term Debt	**(2.1)**	3.7
Dividends Paid	**(2.0)**	(2.0)
Issuance of Common Stock	**0.2**	0.3
Other, net	**(0.1)**	(0.3)
Cash Provided by (Used in) Financing Activities	**(4.0)**	1.7
Net (Decrease) in Cash	**(0.6)**	(1.8)
Cash at Beginning of Period	**4.6**	4.6
Cash at End of Period	**$ 4.0**	$ 2.8
Supplemental Cash Flow Information:		
Interest Paid	**$ 2.1**	$ 2.0
Income Taxes Paid	**0.2**	1.8

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three months ended March 31, 2008 are not necessarily indicative of results to be expected for the year ending December 31, 2008. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2007, as filed with the SEC on February 12, 2008, for a description of the Company's Basis of Presentation.

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In March 2008, the FASB issued FASB Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" (SFAS No. 161) , effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption allowed. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of an entity's use of derivative instruments and the effect of those derivative instruments on an entity's financial statements. The Company adopted SFAS No. 161 and there was no impact on its financial statements.

In December 2007, the FASB issued FASB Statement No. 141 (Revised 2007), "Business Combinations" (SFAS No. 141R), effective prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141R establishes principles and requirements on how an acquirer recognizes and measures in its financial statements identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree, goodwill or gain from a bargain purchase and accounting for transaction costs. Additionally, SFAS No. 141R determines what information must be disclosed to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The Company will adopt SFAS No. 141R upon its effective date and expects the adoption to affect any business combinations effected on or subsequent to that date.

In September 2006, the FASB issued FASB Statement No. 157, "Fair Value Measurements", (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Certain requirements of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS No. 157 has been deferred for one year by the FASB. The Company adopted the sections of SFAS No. 157 which are effective for fiscal years beginning after November 15, 2007 and there was no additional impact on the Company's Consolidated Financial Statements. The Company's fixed rate long-term debt falls under the fair value reporting requirements of SFAS No. 157. Accordingly, the Company has estimated the fair value of its long-term debt as of March 31, 2008 based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities (See Note 4). The Company does not expect that the adoption of the deferred sections of SFAS No. 157 will have an impact on the Company's Consolidated Financial Statements.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
03/20/08	05/15/08	05/01/08	$ 0.345
01/17/08	02/15/08	02/01/08	$ 0.345
09/13/07	11/15/07	11/01/07	$ 0.345
06/21/07	08/15/07	08/01/07	$ 0.345
03/22/07	05/15/07	05/01/07	$ 0.345
01/18/07	02/15/07	02/01/07	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first quarter of 2008, the Company sold 7,596 shares of its Common Stock, at an average price of $27.94 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $212,000 were used to reduce short-term borrowings.

During the first quarter of 2007, the Company sold 9,628 shares of its Common Stock, at an average price of $26.19 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $252,000 were used to reduce short-term borrowings.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 6, 2008, 15,540 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $445,998. Compensation expense associated with shares issued under the Plan is recognized ratably as the shares vest and was $0.1 million and $0.1 million for three months ended March 31, 2008 and 2007, respectively. At March 31, 2008, there was approximately $1.1 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 2.9 years as the shares vest.

Details on preferred stock at March 31, 2008, March 31, 2007 and December 31, 2007 are shown below:

(Amounts in Millions)

	(Unaudited) March 31, 2008	(Unaudited) March 31, 2007	December 31, 2007
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.9**	0.9	0.9
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.1**	$ 2.1	$ 2.1

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at March 31, 2008, March 31, 2007 and December 31, 2007 are shown below:

(Amounts in Millions)

	(Unaudited) March 31, 2008	(Unaudited) March 31, 2007	December 31, 2007
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	$ **20.0**	$ ---	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5.0**	5.3	5.0
Total Long-Term Debt	**160.0**	140.3	160.0
Less: Current Portion	**0.4**	0.3	0.4
Total Long-term Debt, Less Current Portion	**$ 159.6**	$ 140.0	$ 159.6

The fair value of the Company’s long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at March 31, 2008 is estimated to be approximately $166 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company’s policy is to limit these guarantees to two years or less. As of March 31, 2008 there are $6 million of guarantees outstanding and these guarantees extend through October 31, 2009. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, “Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.”

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three months ended March 31, 2008 and March 31, 2007:

Three Months Ended March 31, 2008 (Millions)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$ 56.6**	**$ 14.3**	**$ ---**	**$ 1.0**	**$ 71.9**
Segment Profit	**0.5**	**2.8**	**(0.1)**	**0.1**	**3.3**
Identifiable Segment Assets	**330.2**	**111.2**	**26.9**	**1.0**	**469.3**
Capital Expenditures	**4.2**	**0.3**	**---**	**---**	**4.5**
Three Months Ended March 31, 2007 (Millions)					
Revenues	$ 62.7	$ 14.2	$ ---	$ 0.9	$ 77.8
Segment Profit (Loss)	1.4	1.1	0.1	---	2.6
Identifiable Segment Assets	347.1	114.0	20.9	1.1	483.1
Capital Expenditures	9.1	0.7	(0.2)	---	9.6

NOTE 6 – REGULATORY MATTERS

UNITIL’S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION’S FORM 10-K FOR DECEMBER 31, 2007 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 12, 2008.

FG&E – Electric Division – On December 3, 2007, FG&E submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan (the Annual Reconciliation Filing). The rates were approved effective January 1, 2008, subject to reconciliation pursuant to the MDPU’s investigation. This matter remains pending.

On August 17, 2007, FG&E filed an electric distribution rate increase of $3.3 million, which represented an increase of 4.7 percent over FG&E’s 2006 total electric operating revenue. Evidentiary hearings were held in November 2007 and briefing was completed in January 2008. On February 29, 2008, the Company received a final order from the MDPU approving an electric distribution rate increase of $2.1 million, which represents an increase of 3.0 percent over FG&E’s 2006 total electric operating revenue. The order also provides for recovery of approximately $0.1 million annually of supply-related operating and administrative costs through default service rates. The new electric rates were effective as of March 1, 2008.

FG&E – Other – On June 22, 2007, the MDPU opened an inquiry into revenue decoupling, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to administer and promote customer efforts to reduce energy consumption and demand or to install distributed generation to displace electricity delivered by the utility. This matter remains pending.

UES – On March 14, 2008, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2008, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. The filing is pending, subject to investigation. A hearing is scheduled for April 22, 2008.

On June 22, 2007, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. On August 31, 2007, the NHPUC issued an order on motion for rehearing, staying the June 22, 2007 order pending hearing and reconsideration of the issues. An order following rehearing was issued on January 22, 2008 finding that it is appropriate to implement time-based metering standards and ordering that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes shall be determined in separate proceedings to be initiated by the Commission.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. On March 13, 2008, the NHPUC issued a letter seeking written comments regarding the utilities experience with declining sales attributable to energy conservation, energy efficiency, and demand response and whether existing rate treatment poses an obstacle to investment in energy efficiency. Comments are due April 11, 2008.

Unitil Corp. – On February 15, 2008, Unitil reached agreement with NiSource Inc. and Bay State Gas Company to purchase 100 percent of the ownership shares of Northern Utilities, Inc. and Granite State Gas Transmission, Inc. for $160 million plus a net working capital adjustment. The Company has entered into a senior unsecured bridge facility, which is available to finance this transaction. The Company anticipates either financing the initial acquisition or refinancing the bridge facility with the issuance of a combination of unsecured senior notes and common/or preferred equity securities. On March 31, 2008, Unitil filed petitions and testimony with both the Maine Public Utilities Commission and the New Hampshire Public Utilities Commission requesting approval of the acquisitions. As of March 31, 2008, the Company has capitalized $1.1 million of transaction costs associated with the acquisition. The transaction is expected to close by the fourth quarter of 2008, subject to approval by these commissions and review by certain federal agencies.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2007 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 12, 2008.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of March 31, 2008, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at March 31, 2008, in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts. A corresponding regulatory asset was recorded to reflect the future rate recovery of these costs. As noted above, please refer to Note 5 to the financial statements in Item 8 of Part II of the Company's Form 10-K for December 31, 2007 for additional information. As discussed above, the Company received an insurance settlement during the first quarter of 2008. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.
- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) – The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.
- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) – The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

	2008	2007
Used to Determine Plan Costs		
Discount Rate	**6.00%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2016
Used to Determine Benefit Obligations:		
Discount Rate	**6.00%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2016

The following table provides the components of the Company's Retirement plan costs ($000's):

Three Months Ended March 31,	Pension Plan 2008	Pension Plan 2007	PBOP Plan 2008	PBOP Plan 2007	SERP 2008	SERP 2007
Service Cost	**$ 488**	$ 492	**$ 355**	$ 358	**$ 37**	$ 41
Interest Cost	**944**	834	**559**	514	**32**	29
Expected Return on Plan Assets	**(1,093)**	(1,047)	**(81)**	(61)	**---**	---
Prior Service Cost Amortization	**27**	27	**340**	340	**---**	---
Transition Obligation Amortization	**---**	---	**5**	5	**---**	---
Actuarial Loss Amortization	**319**	336	**---**	17	**6**	11
Sub-total	**685**	642	**1,178**	1,173	**75**	81
Amounts Capitalized and Deferred	**(201)**	(217)	**(439)**	(513)	**---**	---
Net Periodic Benefit Cost Recognized	**$ 484**	$ 425	**$ 739**	$ 660	**$ 75**	$ 81

Employer Contributions

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company expects to contribute approximately $2.8 million to fund its Pension Plan in 2008.

As of March 31, 2008, the Company had made $0.5 million and $18,000 of contributions to the PBOP and SERP Plans, respectively, in 2008. The Company presently anticipates contributing an additional $2.0 million and $54,000 to the PBOP and SERP Plans, respectively, in 2008.

NOTE 9: INCOME TAXES

The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2007 and for the current interim reporting period ended March 31, 2008 in accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2004; December 31, 2005; and December 31, 2006. Income tax filings for the year ended December 31, 2007 have been extended and are due September 15, 2008. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no interest and penalties recognized in the statement of earnings or accrued on the balance sheets.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. *Controls and Procedures*

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company’s Form 10-K for the year-ended December 31, 2007 as filed with the Securities and Exchange Commission on February 12, 2008, other than the risks associated with the Company’s recently announced acquisition of Northern and Granite, as discussed in the Cautionary Statement section of Part I, Item 2 of this Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended March 31, 2008.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), adopted by the Company on March 20, 2008, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors’ annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases. There were no Company repurchases during the three months ended March 31, 2008.

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated April 23, 2008 Announcing Earnings For the Quarter Ended March 31, 2008.	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: April 24, 2008

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: April 24, 2008

/s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING
(Millions, except for per share data)
(UNAUDITED)

	Three Months Ended March 31,	
	2008	2007
Net Income	**$3.3**	$2.6
Less: Dividend Requirements on Preferred Stock	**---**	---
Net Income Applicable to Common Stock	**$3.3**	$2.6
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**5,719**	5,627
Dilutive Effect of Stock Options and Restricted Stock (000's)	**5**	17
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**5,724**	5,644
Earnings Per Share – Basic	**$0.57**	$0.46
Earnings Per Share – Diluted	**$0.57**	$0.46

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 24, 2008

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 24, 2008

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 24, 2008

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	April 24, 2008
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	April 24, 2008
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	April 24, 2008

For Immediate Release

Exhibit 99.1

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports First Quarter Earnings

Hampton, NH – April 23, 2008: Unitil Corporation (AMEX: UTL) (www.unitil.com) today announced net income of $3.3 million for the first quarter of 2008, an increase of $0.7 million over net income for the first quarter of 2007. Earnings per common share (EPS) were $0.57 for the three months ended March 31, 2008, an improvement of $0.11 per share, or 24%, over the first quarter of 2007.

Unitil's improved first quarter earnings in 2008 over 2007 were driven by higher gas sales margin and lower operating expenses, including the benefit from the proceeds of an insurance settlement associated with environmental remediation costs. These favorable factors were partially offset by higher amortization expenses and higher interest expense in the current year.

"We achieved a number of significant milestones in the first quarter of 2008 including the announcement of a Definitive Agreement with NiSource Inc. for the purchase of Northern Utilities and Granite State Gas Transmission," said Robert G. Schoenberger, Unitil's Chairman and Chief Executive Officer. "We also concluded an electric base rate case in Massachusetts providing an annualized revenue increase going forward of $2.1 million and achieved an important insurance settlement."

Unitil has filed with the New Hampshire and Maine Public Utilities Commission for approval of its acquisition of Northern Utilities for a purchase price of $160 million plus working capital. The transaction is expected to close in the fourth quarter of 2008.

The following table presents the significant items contributing to the improvement in earnings per share in the first quarter of 2008:

	Earnings Per Share
Three Months Ended March 31, 2007:	**$ 0.46**
Electric Sales Margin	(0.04)
Gas Sales Margin	0.10
Usource™ Sales Margin	0.01
Operation & Maintenance Expense	0.19
Depreciation, Amortization, Taxes & Other	(0.10)
Interest Expense, Net	(0.05)
Three Months Ended March 31, 2008:	**$ 0.57**

Total electric kilowatt (kWh) sales decreased 1.4% in the three month period ended March 31, 2008 compared to the same period in 2007. Gas sales in the three month period ended March 31, 2008 decreased 1.7% compared to the same period in 2007. The lower unit sales in 2008 compared to 2007 were driven by milder winter weather this year and lower average usage by our customers reflecting a slowing economy and energy conservation.

Electric sales margin was lower by $0.4 million in the three months ended March 31, 2008 compared to the same period in 2007 due to lower electric kWh sales volumes, partially offset by higher electric base rates.

Gas sales margin increased $0.9 million in the three months ended March 31, 2008 compared to the same period in 2007 reflecting higher gas base rates, implemented in 2007.

Usource™ revenues increased $0.1 million in the three month period ended March 31, 2008 over the comparable 2007 period.

Selected financial data for 2008 is presented in the following table:

Unitil Corporation - Condensed Financial Data

(Millions, except Per Share Data) (Unaudited)

	Three Months Ended March 31,		
	2008	**2007**	**Change**
Electric Kilowatt-Hours:			
Residential	182.4	184.0	(0.9%)
Commercial/Industrial	261.1	265.6	(1.7%)
Total Electric kWh Sales	**443.5**	**449.6**	**(1.4%)**
Gas Therms:			
Residential	4.8	4.9	(2.0%)
Commercial/Industrial	6.8	6.9	(1.4%)
Total Gas Therm Sales	**11.6**	**11.8**	**(1.7%)**
Electric Revenues	**$ 56.6**	**$ 62.7**	**$ (6.1)**
Purchased Electricity	43.5	49.2	(5.7)
Electric Sales Margin	**13.1**	**13.5**	**(0.4)**
Gas Revenues	**14.3**	**14.2**	**0.1**
Purchased Gas	9.0	9.8	(0.8)
Gas Sales Margin	**5.3**	**4.4**	**0.9**
Usource™ Sales Margin	**1.0**	**0.9**	**0.1**
Operation & Maintenance	4.7	6.5	(1.8)
Depreciation, Amortization, Taxes & Other	8.8	7.6	1.2
Interest Expense, Net	2.6	2.1	0.5
Net Income	**$ 3.3**	**$ 2.6**	**$ 0.7**
Earnings Per Share	**$ 0.57**	**$ 0.46**	

Total Operation & Maintenance (O&M) expenses decreased $1.8 million for the three month period ended March 31, 2008 compared to the same period in 2007. This decrease reflects a reduction to operating expenses of $2.8 million from the proceeds of an insurance settlement associated with environmental remediation costs. This reduction to operating expenses was partially offset by annual increases in salary, wage and benefit costs of $0.7 million, higher professional fees of $0.2 million and higher bad debt expenses of $0.1 million.

Depreciation, Amortization, Taxes & Other expenses increased $1.2 million in the three month period ended March 31, 2008 compared to the same period in 2007 primarily reflecting the amortization of $0.7 million of natural gas inventory carrying costs and higher income taxes on higher levels of pre-tax earnings in 2008 compared to 2007.

Interest Expense, Net increased $0.5 million in the three month period ended March 31, 2008 compared to the same period in 2007 primarily reflecting higher debt outstanding.

Also in the first quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

About Unitil

Unitil is a public utility holding company with subsidiaries providing electric service in New Hampshire and electric and gas service in Massachusetts and energy services throughout the Northeast. Its subsidiaries include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Unitil Power Corp., Unitil Realty Corp., Unitil Service Corp. and its non-regulated business segment Unitil Resources, Inc. Usource L.L.C. is a subsidiary of Unitil Resources, Inc. Usource™ is a registered trademark of Unitil Resources, Inc.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended June 30, 2008

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X__

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at August 6, 2008
Common Stock, No par value	5,774,402 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended June 30, 2008

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through two utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with an operating franchise in the southeastern seacoast and capital city areas of New Hampshire. FG&E is a combination gas and electric utility with an operating franchise in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 99,400 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are pure distribution utilities with a combined investment in net utility plant of $251.1 million at June 30, 2008. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource™ (Usource) subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries.

On February 15, 2008, the Company entered into a Stock Purchase Agreement (Agreement) with NiSource Inc. (NiSource) and Bay Sate Gas Company (Bay State, which is a wholly owned utility subsidiary of NiSource), to acquire all of the outstanding stock of Northern Utilities, Inc. (Northern), and Granite State Gas Transmission, Inc. (Granite) for $160 million in cash, which amount is subject to a working capital adjustment. The transaction is expected to be financed by newly issued common stock and debt.

Northern's principal business is the retail distribution of natural gas to approximately 53,000 customers located in 44 coastal New Hampshire and southern Maine communities. Portions of Northern's natural gas service territory are contiguous and overlapping with Unitil's electric distribution service territory in New Hampshire. Granite's principal business is a natural gas transmission company, principally engaged in the business of providing natural gas transportation services to Northern for its access to natural gas pipeline supplies.

Consummation of the acquisition is subject to various closing conditions, including but not limited to the receipt of requisite regulatory approvals from certain federal and state public utility, antitrust and other regulatory authorities. It is currently anticipated that the acquisition will be consummated in the fourth quarter of 2008. However, no assurance can be given that the acquisition will occur, or, the timing of its completion.

RATES AND REGULATION

Unitil's utility operations related to wholesale and interstate business activities are regulated by the Federal Energy Regulatory Commission (FERC). The retail distribution utilities, UES and FG&E, are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Public Utilities (MDPU), formerly the Massachusetts Department of Telecommunications and Energy, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets.

As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities provide for the delivery of that supply of electricity over their distribution systems at regulated rates. Both UES and FG&E continue to provide basic or default electric supply service to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition; and
- Customers' future performance under multi-year energy brokering contracts.
- Risks associated with the acquisition of Northern and Granite, discussed above include:
    - Successful integration of the acquired business into the Company;
    - Receipt of regulatory approval of the transaction;
    - Ability to finance transaction at reasonable terms; and
    - Acquisition costs expended for banker fees, legal fees and other acquisition related expenses would adversely affect the Company's financial condition if the acquisition is not completed;

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2007 as filed with the Securities and Exchange Commission on February 12, 2008, other than the risks disclosed above associated with the acquisition of Northern and Granite.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended June 30, 2008 and June 30, 2007 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 1 of this report.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $1.6 million for the second quarter of 2008, compared to net income of $1.7 million for the second quarter of 2007. Earnings per common share (EPS) were $0.28 for the three months ended June 30, 2008 compared with $0.30 in the second quarter of 2007. Earnings for the second quarter of 2008 reflect higher gas utility sales margins and lower interest expense offset by higher operating expenses and depreciation in the quarter. For the six months ended June 30, EPS were $0.85 for 2008 compared to $0.76 for 2007, an increase of $0.09 per share, or 12%.

The following table presents the significant items (discussed below) contributing to the change in earnings per share in the three and six month periods ended June 30, 2008:

2008 Earnings Per Share vs. 2007

		Period Ended June 30,	
		QTD	**YTD**
	2007	**$ 0.30**	**$ 0.76**
Electric Sales Margin		---	(0.04)
Gas Sales Margin		0.02	0.12
Usource Sales Margin		(0.01)	---
Operation & Maintenance Expense		(0.02)	0.17
Depreciation, Amortization & Other		(0.02)	(0.12)
Interest Expense, Net		0.01	(0.04)
	2008	**$ 0.28**	**$ 0.85**

Unitil's total electric kilowatt (kWh) sales decreased 3.1% and 2.2% in the three and six month periods ended June 30, 2008, respectively compared to the same periods in 2007. Natural gas sales in the three and six month periods ended June 30, 2008 decreased 4.6% and 2.2%, respectively, compared to the same periods in 2007. The lower unit sales in 2008 compared to 2007 reflect a milder winter heating season this year and lower average usage by our customers reflecting a slowing economy and energy conservation.

Electric sales margin was flat in the three month period ended June 30, 2008 compared to the same period in 2007. For the six month period ended June 30, 2008, electric sales margin decreased $0.4 million compared to the same period in 2007. The decrease in electric sales margin primarily reflects lower sales volumes, which was partially offset by higher electric base rates, implemented in March of 2008.

Natural gas sales margin increased $0.2 million and $1.1 million in the three and six months ended June 30, 2008, respectively, compared to the same periods in 2007 primarily reflecting higher gas base rates, implemented in November of 2007, partially offset by lower sales volumes.

Usource revenues decreased by $0.1 million in the three month period ended June 30, 2008 compared to the same period in 2007 and were flat in the six month period ended June 30, 2008 compared to the same period in 2007.

Total O&M expenses increased $0.2 million for the three month period ended June 30, 2008 compared to the same period in 2007. The increase in the three month period reflects higher salary and benefit costs of $0.4 million and higher bad debt expense of $0.1 million partially offset by lower utility operating costs of $0.1 million and lower professional fees and all other expenses of $0.2 million. For the six month period ended June 30, 2008, O&M expenses decreased $1.6 million compared to the same period in 2007, including a reduction of $2.8 million from the proceeds of an insurance settlement and lower other utility operating costs of $0.3 million, partially offset by increases in salary and benefit costs of $1.1 million, higher bad debt expenses of $0.2 million and all other expenses, net of $0.2 million.

Depreciation, Amortization, Taxes & Other expenses increased $0.1 million and $1.3 million in the three and six month periods ended June 30, 2008 compared to the same periods in 2007, primarily reflecting the amortization, in the first quarter of 2008, of $0.7 million of natural gas inventory carrying costs deferred under a previous regulatory ruling and higher depreciation on normal utility plant additions.

Interest Expense, Net decreased $0.1 million for the three month period ended June 30, 2008 compared to the same period in 2007. The decrease in the three month period reflects lower short term borrowings. For the six month period ended June 30, 2008, Interest Expense, Net increased $0.4 million compared to the same period in 2007, reflecting higher overall debt outstanding.

Also in the second quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

A more detailed discussion of the Company's results of operations for the three and six months ended June 30, 2008 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

The Company's investment in Net Utility Plant increased by $7.3 million as of June 30, 2008 compared to June 30, 2007. This increase was due to capital expenditures related to UES' and FG&E's electric and gas distribution systems, including expenditures of approximately $1.2 million for the Company's Advanced Metering Infrastructure (AMI) project.

Regulatory Assets decreased $31.1 million as of June 30, 2008 compared to June 30, 2007, primarily reflecting current year cost recoveries. A significant portion of this decrease is matched by a corresponding decrease of $19.9 million in Power Supply Contract Obligations. The remaining decrease primarily reflects lower levels of Regulatory Assets associated with deferred taxes and retirement benefit obligations as well as recoveries of deferred charges.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Unitil's total electric kilowatt (kWh) sales decreased 3.1% and 2.2% in the three and six month periods ended June 30, 2008, respectively compared to the same periods in 2007. Electric kWh sales to residential customers in the three and six month periods ended June 30, 2008 decreased 3.0% and 1.8%, respectively, compared to the same periods in 2007 while sales to C&I customers decreased 3.2% and 2.5%, respectively, in those periods compared to the same periods in 2007. The lower kWh sales in 2008 compared to 2007 were primarily driven by lower average usage by our customers reflecting a slowing economy and energy conservation.

The following table details total kWh sales for the three and six months ended June 30, 2008 and 2007 by major customer class:

kWh Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008	2007	Change	% Change	**2008**	2007	Change	% Change
Residential	**147.5**	152.0	(4.5)	(3.0%)	**329.9**	335.9	(6.0)	(1.8%)
Commercial / Industrial	**254.0**	262.5	(8.5)	(3.2%)	**515.1**	528.2	(13.1)	(2.5%)
Total	**401.5**	414.5	(13.0)	(3.1%)	**845.0**	864.1	(19.1)	(2.2%)

Electric Operating Revenues and Sales Margin - The following table details total Electric Operating Revenues and Sales Margin for the three and six month periods ended June 30, 2008 and 2007:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008	2007	$ Change	% Change[1]	**2008**	2007	$ Change	% Change[1]
Electric Operating Revenue:								
Residential	**$ 25.9**	$ 25.9	$ ---	---	**$ 56.2**	$ 58.6	$ (2.4)	(2.1%)
Commercial / Industrial	**26.1**	25.8	0.3	0.6%	**52.4**	55.8	(3.4)	(3.0%)
Total Electric Operating Revenue	**$ 52.0**	$ 51.7	$ 0.3	0.6%	**$ 108.6**	$ 114.4	$ (5.8)	(5.1%)
Cost of Electric Sales:								
Purchased Electricity	**$ 36.8**	$ 36.3	$ 0.5	1.0%	**$ 79.7**	$ 84.5	$ (4.8)	(4.3%)
Conservation & Load Management	**0.8**	1.0	(0.2)	(0.4%)	**1.4**	2.0	(0.6)	(0.5%)
Electric Sales Margin	**$ 14.4**	$ 14.4	$ ---	---	**$ 27.5**	$ 27.9	$ (0.4)	(0.3%)

[1] Represents change as a percent of Total Electric Operating Revenue.

Total Electric Operating Revenues, increased by $0.3 million, or 0.6%, and decreased by $5.8 million, or 5.1%, in the three and six month periods ended June 30, 2008, respectively, compared to the same periods in 2007. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in the three month period reflects higher Purchased Electricity costs of $0.5 million partially offset by lower C&LM revenues of $0.2 million. The net decrease in Total Electric Operating Revenues in the six month period reflects lower Purchased Electricity costs of $4.8 million, lower C&LM revenues of $0.6 million and lower sales margin of $0.4 million.

Purchased Electricity and C&LM revenues increased a net $0.3 million, or 0.6%, and decreased $5.4 million, or 4.8%, of Total Electric Operating Revenues in the three and six month periods ended June 30, 2008, respectively, compared to the same periods in 2007. The increase in the three month period primarily reflects higher electric commodity prices, partially offset by lower sales volumes. The decrease in the six month period reflects lower sales volumes, an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin was flat in the three month period ended June 30, 2008 compared to the same period in 2007. For the six month period ended June 30, 2008, electric sales margin decreased $0.4 million compared to the same period in 2007. The decrease in electric sales margin primarily reflects lower sales volumes, partially offset by higher electric base rates, implemented in March of 2008.

Gas Sales, Revenues and Margin

Therm Sales – Unitil's total therm sales of natural gas in the three and six month periods ended June 30, 2008 decreased 4.6% and 2.2%, respectively, compared to the same periods in 2007. Gas sales to residential customers in the three and six month periods ended June 30, 2008 decreased 8.7% and 4.2%, respectively, compared to the same periods in 2007 while sales to C&I customers decreased 2.4% and 0.9%, respectively, in those periods compared to the same periods in 2007. The decrease in gas sales in 2008 reflects a milder winter heating season this year and lower average usage by our customers reflecting a slowing economy and energy conservation.

The following table details total firm therm sales for the three and six months ended June 30, 2008 and 2007, by major customer class:

Therm Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008	2007	Change	% Change	**2008**	2007	Change	% Change
Residential	**2.1**	2.3	(0.2)	(8.7%)	**6.9**	7.2	(0.3)	(4.2%)
Commercial / Industrial	**4.1**	4.2	(0.1)	(2.4%)	**10.9**	11.0	(0.1)	(0.9%)
Total	**6.2**	6.5	(0.3)	(4.6%)	**17.8**	18.2	(0.4)	(2.2%)

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and six months ended June 30, 2008 and 2007:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008	2007	$ Change	% Change(1)	**2008**	2007	$ Change	% Change(1)
Gas Operating Revenue:								
Residential	**$ 3.5**	$ 3.6	$ (0.1)	(1.6%)	**$ 11.6**	$ 11.7	$ (0.1)	(0.4%)
Commercial / Industrial	**3.1**	2.8	0.3	4.7%	**9.3**	8.9	0.4	1.9%
Total Gas Operating Revenue	**$ 6.6**	$ 6.4	$ 0.2	3.1%	**$ 20.9**	$ 20.6	$ 0.3	1.5%
Cost of Gas Sales:								
Purchased Gas	**$ 3.9**	$ 3.9	$ ---	---	**$ 12.9**	$ 13.7	$ (0.8)	(3.8%)
Conservation & Load Management	**0.1**	0.1	---	---	**0.1**	0.1	---	---
Gas Sales Margin	**$ 2.6**	$ 2.4	$ 0.2	3.1%	**$ 7.9**	$ 6.8	$ 1.1	5.3%

(1) Represents change as a percent of Total Gas Operating Revenue.

Total Gas Operating Revenues increased $0.2 million, or 3.1%, and $0.3 million, or 1.5%, in the three and six month periods ended June 30, 2008, respectively, compared to the same periods in 2007. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in the three month period reflects higher sales margin of $0.2 million. The net increase in Total Gas Operating Revenues in the six month period reflects higher sales margin of $1.1 million, partially offset by lower Purchased Gas costs of $0.8 million.

Purchased Gas and C&LM revenues were flat in the three month period ended June 30, 2008 compared to the same period in 2007 and decreased $0.8 million, or 3.8% of Total Gas Operating Revenues in the six month period ended June 30, 2008 compared to the same period in 2007. The decrease in the six month period reflects lower sales volumes and an increase in the amount of natural gas purchased by customers directly from third-party suppliers, partially offset by higher natural gas commodity prices. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Natural gas sales margin increased $0.2 million and $1.1 million in the three and six months ended June 30, 2008, respectively, compared to the same periods in 2007 primarily reflecting higher gas base rates, implemented in November of 2007, partially offset by lower sales volumes.

Operating Revenue - Other

The following table details total Other Revenue for the three and six months ended June 30, 2008 and 2007:

Other Revenue (000's)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008	2007	$ Change	% Change	**2008**	2007	$ Change	% Change
Other	**$ 0.8**	$ 0.9	$ (0.1)	(11.1%)	**$ 1.8**	$ 1.8	---	---
Total Other Revenue	**$ 0.8**	$ 0.9	$ (0.1)	(11.1%)	**$ 1.8**	$ 1.8	---	---

Total Other Revenue decreased $0.1 million, or 11.1% in the three month period ended June 30, 2008 compared to the same period in 2007. The decrease reflects lower revenues from the Company's non-regulated energy brokering business, Usource. Total Other Revenues for the six month period ended June 30, 2008 were flat compared to the same period in 2007.

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $0.5 million, or 1.4%, and decreased $4.8 million, or 5.7%, in the three and six month periods ended June 30, 2008, respectively, compared to the same periods in 2007. The increase in the three month period primarily reflects higher electric commodity prices, partially offset by lower sales volumes. The decrease in the six month period reflects lower sales volumes, an increase in the amount of electricity purchased by customers directly from third-party suppliers and lower spending on energy efficiency and conservation programs. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas expenses were flat in the three month period ended June 30, 2008 compared to the same period in 2007 and decreased $0.8 million, or 5.8% in the six month period ended June 30, 2008 compared to the same period in 2007. The decrease in the six month period reflects lower sales volumes and an increase in the amount of natural gas purchased by customers directly from third-party suppliers, partially offset by higher natural gas commodity prices. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expenses increased $0.2 million for the three month period ended June 30, 2008 compared to the same period in 2007. The increase in the three month period reflects higher salary and benefit costs of $0.4 million and higher bad debt expense of $0.1 million partially offset by lower utility operating costs of $0.1 million and lower professional fees and all other expenses of $0.2 million. For the six month period ended June 30, 2008, O&M expenses decreased $1.6 million compared to the same period in 2007, including a reduction of $2.8 million from the proceeds of an insurance settlement and lower other utility operating costs of $0.3 million, partially offset by increases in salary and benefit costs of $1.1 million, higher bad debt expenses of $0.2 million and all other expenses, net of $0.2 million.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased $0.2 million, or 18.2% and $0.6 million, or 28.6%, in the three and six month periods ended June 30, 2008 compared to the same periods in 2007. These changes reflect the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense increased by $0.1 million, or 2.3% and $0.8 million, or 9.0% in the three and six month periods ended June 30, 2008, respectively, compared to the same periods in 2007. The increase in the three month period primarily reflects higher depreciation on normal utility plant additions, partially offset by lower amortization on computer systems. The increase in the six month period primarily reflects the amortization, in the first quarter of 2008, of $0.7 million of natural gas inventory carrying costs deferred under a previous regulatory ruling and higher depreciation on normal utility plant additions.

Local Property and Other Taxes - Local Property and Other Taxes in the three month period ended June 30, 2008 were flat compared to the same period in 2007 and increased by $0.2 million, or 6.9% in the six month period ended June 30, 2008 compared to the same period in 2007. This increase was due to higher property tax rates on increased property assessments and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes - Federal and State Income Taxes were lower by $0.1 million in the three month period ended June 30, 2008 compared to the same period in 2007 reflecting lower pre-tax earnings. Federal and State Income Taxes were higher by $0.1 million in the six month period ended June 30, 2008 compared to the same period in 2007 reflecting higher pre-tax earnings.

Other Non-operating Expenses (Income)

Other Non-operating Expenses (Income) increased by less than $0.1 million and by $0.2 million in the three and six month periods ended June 30, 2008 compared to the same periods in 2007. The increase in the six month period reflects an adjustment of $0.1 million in conjunction with the Company's recently approved electric base distribution rate increase in Massachusetts.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (Millions)	**Three Months Ended June 30,**			**Six Months Ended June 30,**		
	2008	2007	Change	**2008**	2007	Change
Interest Expense						
Long-term Debt	$ 2.9	$ 2.8	$ 0.1	$ 5.7	$ 5.3	$ 0.4
Short-term Debt	0.1	0.3	(0.2)	0.4	0.7	(0.3)
Regulatory Liabilities	---	0.2	(0.2)	0.1	0.3	(0.2)
Subtotal Interest Expense	3.0	3.3	(0.3)	6.2	6.3	(0.1)
Interest Income						
Regulatory Assets	(0.6)	(0.7)	0.1	(1.3)	(1.5)	0.2
AFUDC and Other	(0.1)	(0.2)	0.1	---	(0.3)	0.3
Subtotal Interest Income	(0.7)	(0.9)	0.2	(1.3)	(1.8)	0.5
Total Interest Expense, Net	$ 2.3	$ 2.4	$ (0.1)	$ 4.9	$ 4.5	$ 0.4

Interest Expense, Net decreased $0.1 million for the three month period ended June 30, 2008 compared to the same period in 2007. The decrease in the three month period reflects lower short term interest expense. For the six month period ended June 30, 2008, Interest Expense, Net increased $0.4 million compared to the same period in 2007, reflecting higher overall debt outstanding. Interest expense on long-term borrowings increased in both the three and six month periods in 2008 compared to 2007 due to the issuance of new fixed rate long-term debt. On May 2, 2007, Unitil Corporation issued and sold $20 million of 6.33% Senior Long-Term Notes, due May 1, 2022, to institutional investors in the form of a private placement. The Company utilized the proceeds from the long-term Note financing to refinance existing short-term debt and for other corporate purposes of the Company's principal utility subsidiaries. The resulting reduction in average daily short-term bank borrowings lowered short-term debt interest expense in both the three and six month periods in 2008 compared to 2007. An adjustment of $0.2 million in the first quarter of 2008 related to earnings on funds used for capital projects ordered in conjunction with the Company's recently approved electric base distribution rate increase in Massachusetts and lower carrying charges earned on regulatory assets, which are adjusted periodically to reflect prevailing interest rates, also contributed to the increase in Interest Expense, Net in the six month period ended June 30, 2008 compared to the same period in 2007.

CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

At June 30, 2008, Unitil had $37 million in unsecured revolving lines of credit through two banks. The Company had short-term debt outstanding through bank borrowings of $12.8 million and $9.5 million at June 30, 2008 and June 30, 2007, respectively. In addition, Unitil had approximately $4.3 million in cash at June 30, 2008.

On February 15, 2008, the Company entered into a Stock Purchase Agreement with NiSource and Bay State to acquire all of the outstanding stock of Northern Utilities, Inc. and Granite State Gas Transmission, Inc. The Company has a commitment letter to enter into a senior unsecured bridge facility, which may be used to finance this transaction. The Company anticipates either financing the initial acquisition or refinancing the bridge facility with the issuance of a combination of long-term debt and common equity securities.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to the duration of the contracts, which range from less than one month to two and one-half years. As of June 30, 2008, there were approximately $9.0 million of guarantees outstanding and the longest term guarantee extends through October 31, 2009.

The tables below summarize the major sources and uses of cash (in millions) for the three months ended June 30, 2008, compared to the same period in 2007.

Cash Provided by Operating Activities	**$ 19.8**	$ 17.0

Cash Provided by Operating Activities - Cash Provided by Operating Activities was $19.8 million during the six months ended June 30, 2008, an increase of $2.8 million over the comparable period in 2007. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes of $1.2 million, was $4.9 million higher in the first six months of 2008 compared to 2007. Working Capital related cash flows decreased by $0.6 million during the first six months of 2008 compared to the same period in 2007. Deferred Restructuring Charges provided $0.8 million in cash in the second quarter of 2008 compared to the same period in 2007. These charges were deferred in prior periods for collection in current rates. All other changes in operating activities were a net $2.3 million in uses of cash in the first six months of 2008 compared to 2007.

Cash (Used in) Investing Activities	**$ (10.2)**	$ (19.6)

Cash (Used in) Investing Activities - Cash (Used in) Investing Activities was $10.2 million for the six months ended June 30, 2008, a decrease in capital spending of $9.4 million over the comparable period in 2007. This is mainly due to the funding in 2007 and the completion in 2008 of the Company's Advanced Metering Infrastructure ("AMI") project. In the first six months of 2007, capital expenditures included approximately $5.4 million of cash outlays for investment in the AMI project. Capital expenditure projections are subject to changes during the fiscal year.

Cash Provided by (Used in) Financing Activities	**$ (9.9)**	$ 0.2

Cash Provided by (Used in) Financing Activities - Cash (Used in) Financing Activities was $9.9 million in the three months ended June 30, 2008, reflecting an increase in the use of cash of $10.1 million over the comparable period in 2007. In the second quarter of 2007, Unitil received cash proceeds of $20.0 million from the issuance of Senior Long-term Notes, which was used to pay down Short-term Debt. As a result, the Company utilized an additional $10.5 million in short-term debt for the first six months of 2008 compared to the same period in 2007. All other cash flows used in other financing activities aggregated to a net $0.4 million increase in the first six months of 2008 over the comparable period in 2007.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 12, 2008.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDPU and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided below. The Company receives a return on investment on its regulated assets for which a cash outflow has been made.

Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDPU and NHPUC.

Regulatory Assets consist of the following (millions)	June 30, 2008	June 30, 2007	December 31, 2007
Power Supply Buyout Obligations	**$ 62.7**	$ 82.6	$ 72.7
Deferred Restructuring Costs	**28.8**	30.1	30.5
Generation-related Assets	**1.2**	2.1	1.6
Subtotal – Restructuring Related Items	**92.7**	114.8	104.8
Retirement Benefit Obligations	**35.1**	37.2	35.1
Income Taxes	**13.8**	18.3	14.6
Environmental Obligations	**11.3**	13.1	13.1
Other	**3.3**	3.9	2.9
Total Regulatory Assets	**$ 156.2**	$ 187.3	$ 170.5

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations - The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company

sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans”, (SFAS No. 158), an amendment of SFAS No. 87, “Employers’ Accounting for Pensions”, SFAS No. 88, “Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits,” SFAS No. 106, “Employers’ Accounting for Postretirement Benefits other than Pensions” and SFAS No. 132(R), “Employers’ Disclosures about Pensions and Other Postretirement Benefits.” SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

The Company’s reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company’s health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The Company’s RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. The Company’s RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company’s RBO.

If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2007 and 2006, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2007 and 2006, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $690,000 and $683,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $539,000 and $530,000, respectively. (See Note 8)

Income Taxes - Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company’s current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company’s consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, “Accounting for Income Taxes” (SFAS No. 109) and under FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48), an interpretation of FAS 109.

Depreciation - Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company’s fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies - The Company’s accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5. SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of June 30, 2008, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company’s consolidated financial statements below.

Refer to “Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company’s debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company’s short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company’s interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company’s short-term borrowings for the three months ended June 30, 2008 and June 30, 2007 were 2.84% and 5.77%, respectively. The average interest rates on the Company’s short-term borrowings for the six months ended June 30, 2008 and June 30, 2007 were 3.40% and 5.77%, respectively.

MARKET RISK

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Operating Revenues				
Electric	**$ 52.0**	$ 51.7	**$ 108.6**	$ 114.4
Gas	**6.6**	6.4	**20.9**	20.6
Other	**0.8**	0.9	**1.8**	1.8
Total Operating Revenues	**59.4**	59.0	**131.3**	136.8
Operating Expenses				
Purchased Electricity	**36.8**	36.3	**79.7**	84.5
Purchased Gas	**3.9**	3.9	**12.9**	13.7
Operation and Maintenance	**7.0**	6.8	**11.7**	13.3
Conservation & Load Management	**0.9**	1.1	**1.5**	2.1
Depreciation and Amortization	**4.5**	4.4	**9.7**	8.9
Provisions for Taxes:				
Local Property and Other	**1.4**	1.4	**3.1**	2.9
Federal and State Income	**0.7**	0.8	**2.5**	2.4
Total Operating Expenses	**55.2**	54.7	**121.1**	127.8
Operating Income	**4.2**	4.3	**10.2**	9.0
Non-Operating Expenses	**0.2**	0.1	**0.3**	0.1
Income Before Interest Expense	**4.0**	4.2	**9.9**	8.9
Interest Expense, Net	**2.3**	2.4	**4.9**	4.5
Net Income	**1.7**	1.8	**5.0**	4.4
Less: Dividends on Preferred Stock	**0.1**	0.1	**0.1**	0.1
Earnings Applicable to Common Shareholders	**$ 1.6**	$ 1.7	**$ 4.9**	$ 4.3
Average Common Shares Outstanding – Basic (000's)	**5,736**	5,642	**5,728**	5,634
Average Common Shares Outstanding - Diluted (000's)	**5,741**	5,663	**5,733**	5,653
Earnings Per Common Share (Basic and Diluted)	**$ 0.28**	$ 0.30	**$ 0.85**	$ 0.76
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.035**	$ 1.035

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) June 30, 2008	(UNAUDITED) June 30, 2007	December 31, 2007
ASSETS:			
Utility Plant:			
Electric	**$ 272.8**	$ 259.2	$ 266.2
Gas	**69.8**	64.6	67.8
Common	**27.2**	25.6	26.2
Construction Work in Progress	**7.3**	21.5	20.3
Total Utility Plant	**377.1**	370.9	380.5
Less: Accumulated Depreciation	**126.0**	127.1	131.6
Net Utility Plant	**251.1**	243.8	248.9
Current Assets:			
Cash	**4.3**	2.2	4.6
Accounts Receivable – Net of Allowance for Doubtful Accounts of $1.3, $2.4 and $1.3	**22.5**	21.7	24.9
Accrued Revenue	**14.2**	9.0	12.7
Refundable Taxes	**---**	---	0.7
Materials and Supplies	**3.9**	3.3	4.5
Prepayments and Other	**1.6**	1.8	1.5
Total Current Assets	**46.5**	38.0	48.9
Noncurrent Assets:			
Regulatory Assets	**156.2**	187.3	170.5
Debt Issuance Costs, net	**2.7**	2.8	2.8
Other Noncurrent Assets	**7.1**	1.9	3.5
Total Noncurrent Assets	**166.0**	192.0	176.8
TOTAL	**$ 463.6**	$ 473.8	$ 474.6

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) June 30, 2008	June 30, 2007	December 31, 2007
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 100.0**	$ 96.9	$ 100.4
Preferred Stock, Non-Redeemable, Non-Cumulative	**0.2**	0.2	0.2
Preferred Stock, Redeemable, Cumulative	**1.8**	1.8	1.9
Long-Term Debt, Less Current Portion	**159.4**	160.0	159.6
Total Capitalization	**261.4**	258.9	262.1
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.3	0.4
Capitalized Leases, Current Portion	**0.2**	0.3	0.3
Short-Term Debt	**12.8**	9.5	18.8
Accounts Payable	**18.2**	15.1	17.6
Taxes Payable	**0.1**	2.4	---
Interest and Dividends Payable	**3.9**	3.8	1.9
Other Current Liabilities	**4.6**	4.1	5.1
Total Current Liabilities	**40.2**	35.5	44.1
Deferred Income Taxes	**34.2**	31.9	33.4
Noncurrent Liabilities:			
Power Supply Contract Obligations	**62.7**	82.6	72.7
Retirement Benefit Obligations	**51.0**	51.3	48.2
Environmental Obligations	**12.0**	12.0	12.0
Capitalized Leases, Less Current Portion	**0.4**	0.5	0.5
Other Noncurrent Liabilities	**1.7**	1.1	1.6
Total Noncurrent Liabilities	**127.8**	147.5	135.0
TOTAL	**$ 463.6**	$ 473.8	$ 474.6

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Six Months Ended June 30,			
	2008		2007	
Operating Activities:				
Net Income	**$**	**5.0**	$	4.4
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:				
Depreciation and Amortization		**9.7**		8.9
Deferred Taxes		**1.2**		(2.3)
Changes in Current Assets and Liabilities:				
Accounts Receivable		**2.4**		0.8
Accrued Revenue		**(1.5)**		4.8
Accounts Payable		**0.6**		(4.7)
Taxes Payable		**0.8**		1.5
All other Current Assets and Liabilities		**---**		0.5
Deferred Restructuring Charges		**1.7**		0.9
Other, net		**(0.1)**		2.2
Cash Provided by Operating Activities		**19.8**		17.0
Investing Activities:				
Property, Plant and Equipment Additions		**(10.2)**		(19.6)
Cash (Used in) Investing Activities		**(10.2)**		(19.6)
Financing Activities:				
Proceeds From (Repayment of) Short-Term Debt, net		**(6.0)**		(16.5)
Proceeds From (Repayment of) Long-Term Debt		**(0.2)**		20.0
Dividends Paid		**(4.0)**		(4.0)
Issuance of Common Stock		**0.5**		0.5
Retirement of Preferred Stock		**---**		(0.1)
Other, net		**(0.2)**		0.3
Cash (Used in) Provided by Financing Activities		**(9.9)**		0.2
Net (Decrease) in Cash		**(0.3)**		(2.4)
Cash at Beginning of Period		**4.6**		4.6
Cash at End of Period	**$**	**4.3**	$	2.2
Supplemental Cash Flow Information:				
Interest Paid	**$**	**6.1**	$	5.7
Income Taxes Paid	**$**	**0.5**	$	3.3

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and six months ended June 30, 2008 are not necessarily indicative of results to be expected for the year ending December 31, 2008. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2007, as filed with the SEC on February 12, 2008, for a description of the Company's Basis of Presentation.

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – In May 2008, the FASB issued FASB Statement No. 162, "The Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 162), effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board's amendments to AU Section 411. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States. The Company will adopt SFAS No. 162 when it is approved and does not expect it to have any impact on its financial statements.

In March 2008, the FASB issued FASB Statement No. 161, “Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133” (SFAS No. 161), effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption allowed. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of an entity’s use of derivative instruments and the effect of those derivative instruments on an entity’s financial statements. The Company adopted SFAS No. 161 and there was no impact on its financial statements.

In December 2007, the FASB issued FASB Statement No. 141 (Revised 2007), “Business Combinations” (SFAS No. 141R), effective prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141R establishes principles and requirements on how an acquirer recognizes and measures in its financial statements identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree, goodwill or gain from a bargain purchase and accounting for transaction costs. Additionally, SFAS No. 141R determines what information must be disclosed to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The Company will adopt SFAS No. 141R upon its effective date and expects the adoption to affect any business combinations effected on or subsequent to that date.

In September 2006, the FASB issued FASB Statement No. 157, “Fair Value Measurements”, (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Certain requirements of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS No. 157 has been deferred for one year by the FASB. The Company adopted the sections of SFAS No. 157 which are effective for fiscal years beginning after November 15, 2007 and there was no additional impact on the Company’s Consolidated Financial Statements. The Company’s fixed rate long-term debt falls under the fair value reporting requirements of SFAS No. 157. Accordingly, the Company has estimated the fair value of its long-term debt as of June 30, 2008 based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities (See Note 4). The Company does not expect that the adoption of the deferred sections of SFAS No. 157 will have an impact on the Company’s Consolidated Financial Statements.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
06/19/08	08/15/08	08/01/08	$ 0.345
03/20/08	05/15/08	05/01/08	$ 0.345
01/17/08	02/15/08	02/01/08	$ 0.345
09/13/07	11/15/07	11/01/07	$ 0.345
06/21/07	08/15/07	08/01/07	$ 0.345
03/22/07	05/15/07	05/01/07	$ 0.345
01/18/07	02/15/07	02/01/07	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first six months of 2008, the Company sold 14,889 shares of its Common Stock, at an average price of $27.76 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $413,000 were used to reduce short-term borrowings.

During the first six months of 2007, the Company sold 19,199 shares of its Common Stock, at an average price of $26.59 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $511,000 were used to reduce short-term borrowings.

Also, in the second quarter of 2008, the Company issued and sold 3,000 shares of its Common Stock, at an average price of $24.63 per share, in connection with the exercise of stock options under the Unitil Corporation 1998 Stock Option Plan (1998 Plan). Net proceeds of $73,875 were used by the Company to reduce short-term borrowings. As disclosed in Note 2 to the Company's Form 10-K for the year ended December 31, 2007, the 1998 Plan became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, were determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vested over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's Common Stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. This plan was terminated on January 16, 2003. There was no compensation expense associated with this plan in 2008 and 2007. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of options will be made under this plan. As of June 30, 2008, there are 104,000 options vested and exercisable outstanding.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 6, 2008, 15,540 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $445,998. Compensation expense associated with shares issued under the Plan is recognized ratably as the shares vest and was $0.2 million and $0.2 million for six months ended June 30, 2008 and 2007, respectively. At June 30, 2008, there was approximately $1.0 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 2.8 years as the shares vest.

Details on preferred stock at June 30, 2008, June 30, 2007 and December 31, 2007 are shown below:

(Amounts in Millions)

	(Unaudited) June 30,		December 31,
	2008	2007	2007
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.8	0.9
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.0**	$ 2.0	$ 2.1

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at June 30, 2008, June 30, 2007 and December 31, 2007 are shown below:

(Amounts in Millions)

	(Unaudited) June 30, 2008	(Unaudited) June 30, 2007	December 31, 2007
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	$ **20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**4.8**	5.3	5.0
Total Long-Term Debt	**159.8**	160.3	160.0
Less: Current Portion	**0.4**	0.3	0.4
Total Long-term Debt, Less Current Portion	**$ 159.4**	$ 160.0	$ 159.6

The fair value of the Company’s long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at June 30, 2008 is estimated to be approximately $162 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company’s policy is to limit these guarantees to two years or less. As of June 30, 2008 there are $9 million of guarantees outstanding and these guarantees extend through October 31, 2009. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, “Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.”

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and six months ended June 30, 2008 and June 30, 2007 (Millions):

Three Months Ended:	Electric	Gas	Other	Non-Regulated	Total
June 30, 2008					
Revenues	**$ 52.0**	**$ 6.6**	**$ ---**	**$ 0.8**	**$ 59.4**
Segment Profit (Loss)	**2.0**	**(0.3)**	**(0.1)**	**---**	**1.6**
Capital Expenditures	**5.4**	**0.2**	**0.1**	**---**	**5.7**
June 30, 2007					
Revenues	$ 51.7	$ 6.4	$ ---	$ 0.9	$ 59.0
Segment Profit (Loss)	2.0	(0.4)	---	0.1	1.7
Capital Expenditures	8.0	1.5	0.5	---	10.0
Six Months Ended:					
June 30, 2008					
Revenues	**$ 108.6**	**$ 20.9**	**$ ---**	**$ 1.8**	**$ 131.3**
Segment Profit (Loss)	**2.5**	**2.5**	**(0.2)**	**0.1**	**4.9**
Capital Expenditures	**9.6**	**0.5**	**0.1**	**---**	**10.2**
Segment Assets	**326.2**	**108.5**	**27.9**	**1.0**	**463.6**
June 30, 2007					
Revenues	$ 114.4	$ 20.6	$ ---	$ 1.8	$ 136.8
Segment Profit (Loss)	3.4	0.7	0.1	0.1	4.3
Capital Expenditures	17.1	2.2	0.3	---	19.6
Segment Assets	339.5	110.6	22.6	1.1	473.8

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2007 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 12, 2008.

FG&E – Electric Division – On December 3, 2007, FG&E submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan (the Annual Reconciliation Filing). The rates were approved effective January 1, 2008, subject to reconciliation pursuant to the MDPU's investigation. On June 6, 2008, FG&E submitted a revised Transition Charge reducing the recovery of net costs associated with the sale of Wyman 4 by $36,762 pursuant to an agreement with the Attorney General. This matter remains pending before the MDPU.

FG&E – Other – On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to administer and promote customer efforts to reduce energy consumption and demand or to install distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis. Company specific rate cases will be required. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012. Within 45 days of this order, each distribution company must notify the MDPU of when the company expects to file a rate case to implement decoupling.

On July 2, 2008, Massachusetts Senate Bill No. 2768 (the "Green Communities Act") was signed into law. The Green Communities Act is intended to increase energy efficiency, update the renewable energy portfolio standard, increase public oversight of utilities, increase service quality of power companies, assist low-income energy customers, and increase the use of renewable generation and energy efficiency products. The Act requires electric companies to boost investment in energy efficiency measures that reduce energy demand and deliver savings to customers; provides a new funding source for efficiency measures through the auction of pollution allowances by power plants through the Regional Greenhouse Gas Initiative; creates stronger incentives for the development of renewable energy, like wind and solar, by requiring 15 percent of electricity to be supplied by new green power facilities by 2020 and establishing a pilot program for utilities to enter into long-term contracts with renewable energy projects; expressly authorizes cities and towns to own renewable energy facilities; and encourages green building design through updated codes, training and assistance. The MDPU is expected to initiate regulatory proceedings to implement various sections of the Act. The impact of any new measures to be required of FG&E in compliance with the Act cannot be estimated at this time.

UES –In July, 2008, the State of New Hampshire passed a law that allows electric utilities to make investments in distributed energy resources including energy efficiency and demand reduction technologies as well as clean cogeneration and renewable generation. In June, 2008, The State of New Hampshire also passed a law approving state participation in the Regional Greenhouse Gas Initiative ("RGGI"). The RGGI program begins in 2009 and requires large electric generators in the 10-state northeast region to purchase allowances for their carbon emissions. These allowances are being sold through a regional auction process and the funds will be used by the states for investments in energy efficiency and alternative energy.

On March 14, 2008, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective May 1, 2008, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. The filing was approved on April 23, 2008. On July 9, 2008, UES proposed an increase to its External Delivery Charge, effective September 1, 2008, reflecting higher transmission costs.

On June 22, 2007, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. On August 31, 2007, the NHPUC issued an order on motion for rehearing, staying the June 22, 2007 order pending hearing and reconsideration of the issues. An order following rehearing was issued on January 22, 2008 finding that it is appropriate to implement some form of time-based metering standards and ordering that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes shall be determined in separate proceedings to be initiated by the Commission.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. This matter remains pending before the NHPUC.

Acquisition of Northern Utilities Inc. and Granite State Gas Transmission, Inc. – On February 15, 2008, the Company entered into a Stock Purchase Agreement (Agreement) with NiSource Inc. (NiSource) and Bay Sate Gas Company (Bay State, which is a wholly owned utility subsidiary of NiSource), to acquire all of the outstanding stock of Northern Utilities, Inc. (Northern), and Granite State Gas Transmission, Inc. (Granite) for $160 million in cash, which amount is subject to a working capital adjustment. The transaction is expected to be financed by newly issued common stock and debt. The Company has a commitment letter to enter into a senior unsecured bridge facility, which may be used to finance this transaction on an interim basis until permanent financing is completed.

On March 31, 2008, Unitil filed joint petitions with Nisource and BaySate along with supporting testimony with the Maine Public Utilities Commission and the New Hampshire Public Utilities Commission requesting approval of the acquisitions. The requests for approval are under active consideration and remain pending. As of June 30, 2008, the Company has deferred $3.4 million of transaction costs associated with the acquisition. The transaction is expected to close by the fourth quarter of 2008, subject to approval by the state commissions and review by certain federal agencies.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2007 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 12, 2008.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of June 30, 2008, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at June 30, 2008, in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts. A corresponding regulatory asset was recorded to reflect the future rate recovery of these costs. As noted above, please refer to Note 5 to the financial statements in Item 8 of Part II of the Company's Form 10-K for December 31, 2007 for additional information. The Company received an insurance settlement during the first quarter of 2008 associated with environmental remediation costs. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) – The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) – The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan Costs	**2008**	2007
Discount Rate	**6.00%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2016

Used to Determine Benefit Obligations:	**2008**	2007
Discount Rate	**6.00%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2016

The following table provides the components of the Company's Retirement plan costs ($000's):

	Pension Plan		**PBOP Plan**		**SERP**	
Three Months Ended June 30,	**2008**	2007	**2008**	2007	**2008**	2007
Service Cost	**$ 488**	$ 492	**$ 355**	$ 358	**$ 37**	$ 41
Interest Cost	**943**	834	**559**	514	**31**	29
Expected Return on Plan Assets	**(1,094)**	(1,050)	**(82)**	(61)	**---**	---
Prior Service Cost Amortization	**27**	27	**341**	340	**---**	---
Transition Obligation Amortization	**---**	---	**6**	5	**---**	---
Actuarial Loss Amortization	**319**	336	**---**	17	**6**	11
Sub-total	**683**	639	**1,179**	1,173	**74**	81
Amounts Capitalized and Deferred	**(246)**	(219)	**(513)**	(504)	**---**	---
Net Periodic Benefit Cost Recognized	**$ 437**	$ 420	**$ 666**	$ 669	**$ 74**	$ 81

	Pension Plan		PBOP Plan		SERP	
Six Months Ended June 30,	**2008**	2007	**2008**	2007	**2008**	2007
Service Cost	**$ 976**	$ 984	**$ 710**	$ 715	**$ 74**	$ 82
Interest Cost	**1,887**	1,669	**1,118**	1,028	**63**	59
Expected Return on Plan Assets	**(2,187)**	(2,097)	**(163)**	(122)	**---**	---
Prior Service Cost Amortization	**54**	53	**681**	679	**---**	(1)
Transition Obligation Amortization	**---**	---	**11**	11	**---**	---
Actuarial Loss Amortization	**638**	672	**---**	35	**12**	22
Sub-total	**1,368**	1,281	**2,357**	2,346	**149**	162
Amounts Capitalized and Deferred	**(447)**	(436)	**(952)**	(1,017)	**---**	---
Net Periodic Benefit Cost Recognized	**$ 921**	$ 845	**$ 1,405**	$ 1,329	**$ 149**	$ 162

Employer Contributions

On August 17, 2006, the Pension Protection Act of 006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company expects to contribute approximately $2.8 million to fund its Pension Plan in 2008.

As of June 30, 2008, the Company had made $1.0 million and $33,000 of contributions to the PBOP and SERP Plans, respectively, in 2008. The Company presently anticipates contributing an additional $1.5 million and $26,000 to the PBOP and SERP Plans, respectively, in 2008.

NOTE 9: INCOME TAXES

The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2007, and at each interim reporting date in the period ended June 30, 2008 in accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2004; December 31, 2005; and December 31, 2006. Income tax filings for the year ended December 31, 2007 have been extended and are due September 15, 2008. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no interest and penalties recognized in the statement of earnings or accrued on the balance sheets.

NOTE 10: SUBSEQUENT EVENT – DEFINITIVE PROXY STATEMENT

On July 29, 2008, the Company filed a Definitive Proxy Statement (Proxy) with the SEC and subsequently mailed the Proxy to the Company's shareholders. The Proxy served as notification that a special meeting of the Company's shareholders will be held at the office of the Company on September 10, 2008 to approve and adopt an amendment to the Company's Articles of Incorporation, as amended, to increase the authorized number of shares of common stock, no par value per share, of the Company from 8,000,000 shares to 16,000,000 shares in the aggregate and to act on such other matters that may come before the meeting and any adjournments.

The Company intends to sell and issue up to 4,000,000 shares of Common Stock in a public offering to partially finance the proposed acquisition by the Company of Northern Utilities, Inc. and Granite State Gas Transmission, Inc., as discussed above in Note 6.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Unaudited Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2007 as filed with the Securities and Exchange Commission on February 12, 2008, other than the risks associated with the Company's recently announced acquisition of Northern and Granite, as discussed in the Cautionary Statement section of Part I, Item 2 of this Quarterly Report on Form 10-Q for the quarter ended June 30, 2008.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended June 30, 2008.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), adopted by the Company on March 20, 2008, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases. Company repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
4/1/08 – 4/30/08	---	---	---	n/a
5/1/08 – 5/31/08	396	$27.68	396	n/a
6/1/08 – 6/30/08	---	---	---	n/a
Total	396	$27.68	396	n/a

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: August 7, 2008 /s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: August 7, 2008 /s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING

(Millions except common shares and per share data)

(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Net Income	**$ 1.7**	$ 1.8	**$ 5.0**	$ 4.4
Less: Dividend Requirements on Preferred Stock	**0.1**	0.1	**0.1**	0.1
Net Income Applicable to Common Stock	**$ 1.6**	$ 1.7	**$ 4.9**	$ 4.3
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**5,736**	5,642	**5,728**	5,634
Dilutive Effect of Stock Options and Restricted Stock (000's)	**5**	21	**5**	19
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**5,741**	5,663	**5,733**	5,653
Earnings Per Share – Basic	**$0.28**	$0.30	**$0.85**	$0.76
Earnings Per Share – Diluted	**$0.28**	$0.30	**$0.85**	$0.76

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2008

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2008

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2008

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending June 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	August 7, 2008
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	August 7, 2008
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	August 7, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For Quarter Ended September 30, 2008

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	*(Zip Code)*

Registrant's telephone number, including area code: (603) 772-0775

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer___ Accelerated filer__X__ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes___ No_X__

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 23, 2008
Common Stock, No par value	5,781,749 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended September 30, 2008

Table of Contents

PART I. FINANCIAL INFORMATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil's principal business is the retail distribution of electricity and natural gas through two utility subsidiaries: Unitil Energy System's Inc. (UES) and Fitchburg Gas and Electric Light Company (FG&E). UES is an electric utility with a service territory in the southeastern seacoast and state capital regions of New Hampshire. FG&E is a combination gas and electric utility with a service territory in the greater Fitchburg area of north central Massachusetts.

Unitil's two retail distribution utilities serve approximately 100,000 electric customers and 15,100 natural gas customers in their franchise areas. The retail distribution utilities are pure distribution utilities with a combined investment in net utility plant of $256.0 million at September 30, 2008. Substantially all of Unitil's revenue and earnings are derived from its regulated utility operations.

Unitil also conducts non-regulated operations principally through its Usource™ (Usource) subsidiary. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and all of its subsidiaries.

On February 15, 2008, the Company entered into a Stock Purchase Agreement with NiSource, Inc. (NiSource) and Bay State Gas Company (Bay State, which is a wholly owned utility subsidiary of NiSource), to acquire all of the outstanding stock of Northern Utilities, Inc. (Northern), and Granite State Gas Transmission, Inc. (Granite) for $160 million in cash, which amount is subject to a working capital adjustment. The transaction is expected to be financed initially with proceeds from newly issued common stock together with a bridge credit facility. In the event that the equity offering is delayed until after the transaction closes, the Company may initially finance the transaction entirely with the bridge facility. The Company expects to repay the bridge facility as soon as practical after the transaction closes using the proceeds from the issuance of notes and newly issued common stock.

On March 31, 2008, Unitil and Northern filed joint petitions and supporting testimony with the Maine Public Utilities Commission (MPUC) and the New Hampshire Public Utilities Commission (NHPUC) requesting approval of the acquisitions. Subsequently, on May 30, 2008, Unitil and Northern filed joint petitions before both the NHPUC and MPUC requesting authority for Northern to issue unsecured long term debt to finance the acquisition of Northern by Unitil. In August, 2008, unopposed stipulation agreements resolving all outstanding issues and recommending approval of the acquisition and the financing petitions were filed with the MPUC and the NHPUC on behalf of Unitil, Northern and the active parties to the respective Maine and New Hampshire proceedings.

On October 10, 2008, the NHPUC issued orders approving the stipulation agreement and the financing petition, and authorizing the acquisition of Northern by Unitil.

On October 6, 2008, the MPUC publicly deliberated the matter and voted to approve the joint petition and stipulation agreement with conditions, subject to its issuance of a final written order. On October 22, 2008, the MPUC issued its written order approving the stipulation agreement and authorizing the acquisition of Northern by Unitil, subject to several conditions. Based on its review of the written order, Unitil expects to file along with Northern, a motion for reconsideration of the order on narrow grounds requesting clarification and/or modification of conditions of approval contained in the order. These conditions would potentially contravene the allocation of risks agreed to by the parties in the stipulation agreement and underlying Stock Purchase Agreement with regard to several pending regulatory safety and compliance proceedings involving Northern. At this time, Unitil can not predict what changes, if any, the MPUC's reconsideration and continued deliberation of this matter will have on its order or the unopposed stipulation agreement of the parties in this proceeding.

As a result of statutory changes in Massachusetts (see discussion of "Green Communities Act in Note 6), on August 13, 2008, Unitil and Bay State also filed a joint petition with the MDPU requesting an advisory ruling that Massachusetts law is not applicable to the proposed transaction, or, in the alternative, that it approve the transaction as consistent with the public interest. The Massachusetts Attorney General has asserted that Massachusetts law grants the MDPU jurisdiction to review the transaction, and argues that Bay State's customers will be harmed by the sale. Unitil and Bay State dispute the Attorney General's assertions. On October 1, 2008, a hearing on the joint petition was held before the MDPU, and on October 10 and October 17 the Parties to the proceeding filed their Initial and Reply Briefs, respectively. The Company has requested a final order from the MDPU on or before November 3, 2008, to allow the Company to proceed with the financing and closing of the transaction in the fourth quarter of 2008. The joint petition remains under active consideration by the MDPU.

Northern's principal business is the retail distribution of natural gas to approximately 52,000 customers located in 44 coastal New Hampshire and southern Maine communities. Portions of Northern's natural gas service territory are contiguous and overlapping with Unitil's electric distribution service territory in New Hampshire. Granite is a natural gas transmission company, principally engaged in the business of providing natural gas transportation services to Northern for its access to natural gas supply from interconnected upstream pipelines.

Consummation of the acquisitions is subject to various closing conditions, including but not limited to the receipt of the requisite regulatory approvals from state public utility commissions, noted above, from the Federal Communications Commission and clearance under federal antitrust regulations, which was received in May of 2008. It is currently anticipated that the acquisition will be consummated in the fourth quarter of 2008. However, no assurance can be given that the acquisition will close at that time, or at all.

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's Common Stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's Common Stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. The Company expects to issue and sell up to 4,000,000 shares in a public offering to partially finance the acquisition of Northern and Granite, discussed above.

On September 12, 2008, the Company priced the anticipated sale and issuance of $80.0 million aggregate principal amount of senior unsecured notes by Northern and $10.0 million aggregate principal amount of senior unsecured notes by Granite, subject to the conditions discussed below. The notes consist of:

(i) $30.0 million aggregate principal amount of 6.95% senior unsecured notes of Northern, which are due in 2018;

(ii) $50.0 million aggregate principal amount of 7.72% senior unsecured notes of Northern, which are due in 2038; and

(iii) $10.0 million aggregate principal amount of 7.15% senior unsecured notes of Granite, which are due in 2018.

The Company agreed to guarantee the payment of principal and interest on the Granite notes.

The Company expects to (i) finance its acquisition of Northern and Granite using the proceeds from a sale and issuance of common stock and a bridge credit facility and (ii) use the proceeds from the sale and issuance of the notes to repay all amounts outstanding under the bridge credit facility. In the event that the sale and issuance of common stock is delayed until after the acquisitions close, the Company may finance the acquisitions entirely with the bridge credit facility. Under those circumstances, the Company expects to repay the bridge facility as soon as practical after the acquisitions close using the proceeds from the issuance of notes and from the sale and issuance of common stock.

The foregoing is not intended to, and does not, constitute an offering of the Northern or Granite notes described above. The sale and issuance of such notes (i) is subject to the execution of definitive note purchase agreements by Northern, Granite and the prospective purchasers of the notes as well as receipt of certain regulatory approvals and satisfaction of closing conditions, including the closing of the acquisitions, (ii) will not be, and has not been, registered under the Securities Act of 1933 and the notes may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements and (iii) is not conditioned upon the closing of the offering of the Company's common stock, as described above. The Company has received the required regulatory approvals from the NHPUC and MPUC for these debt issuances.

As of August 21, 2008 the Company's Common Stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's Common Stock trades under the symbol, "UTL".

RATES AND REGULATION

Unitil's utility operations related to wholesale and interstate business activities are regulated by the Federal Energy Regulatory Commission (FERC). The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the MDPU, formerly the Massachusetts Department of Telecommunications and Energy, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil's primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company's operations and financial position. Following the closing of the acquisitions, Northern will continue to be regulated by the NHPUC and MPUC. Granite, as an interstate natural gas pipeline, will continue to be regulated by the FERC.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their service territories, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets.

As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. The retail distribution utilities provide for the delivery of that supply of electricity over their distribution systems at regulated rates. Both UES and FG&E continue to provide basic or default electric supply service to those customers who do not obtain their supply from third-party suppliers, as a provider of last resort. The costs associated with electricity supplied by the Company are recovered on a pass-through basis under rates that are adjusted periodically during the year.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E provides for the delivery of that gas supply over its gas distribution system at regulated rates and continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under rates that are adjusted periodically during the year.

The NHPUC and MPUC have both announced their approval of Unitil's proposed acquisition of Northern. Regulatory approval for the acquisition is now pending in Massachusetts. The regulatory process in both Maine and New Hampshire included the negotiation and filing of settlement agreements reflecting commitments by Unitil with respect to Northern's rates, customer service and operations and for enhanced safety and reliability programs.

The settlement agreements were separately negotiated and filed in each state but reflect a number of common features. The settlements include commitments by Unitil with respect to Northern's rates, customer service and operations during and after the transition of Northern's management and business operations from NiSource, Northern's current ultimate parent company, to Unitil. Northern will be required to implement enhanced safety and reliability programs and upgrade the customer service quality programs for customers in both states. Unitil will also be required to conduct a study in collaboration with parties in both states of potential changes in organization or regulation of Granite.

CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without

limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding the Company's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions, including recent distress in the financial markets that has had an adverse impact on the availability of credit and liquidity resources generally and could jeopardize certain of our counterparty obligations, including those of our insurers and financial institutions;
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities;
- Increased competition;
- Customers' future performance under multi-year energy brokering contracts; and
- Risks associated with the acquisition of Northern and Granite, discussed above, include:
    - Successful integration of the acquired business into the Company;
    - Receipt of regulatory approval of the transaction and subsequent rate plan;
    - Conditions imposed on the Company under regulator orders related to the acquisition;
    - Ability to finance transaction at reasonable terms; and
    - Acquisition costs expended for banker fees, legal fees and other acquisition related expenses would adversely affect the Company's financial condition if the acquisition is not completed.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2007 as filed with the Securities and Exchange Commission on February 12, 2008, other than the risks disclosed above associated with the acquisition of Northern and Granite and the risks associated with the recent distress in the financial markets.

RESULTS OF OPERATIONS

The following section of MD&A compares the results of operations for each of the two fiscal periods ended September 30, 2008 and September 30, 2007 and should be read in conjunction with the accompanying Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements included in Item 1 of this report.

Earnings Overview

The Company's Earnings Applicable to Common Shareholders (Net Income) was $1.5 million for the third quarter of 2008, compared to net income of $1.6 million for the third quarter of 2007. Earnings per common share (EPS) were $0.27 for the three months ended September 30, 2008 compared with $0.28 in the third quarter of 2007. Earnings for the third quarter of 2008 reflect higher operating expenses and interest expense in the quarter offset by higher electric and gas utility sales margins. For the nine months ended September 30, EPS were $1.12 for 2008 compared to $1.04 for 2007, an increase of $0.08 per share, or 8%.

The following table presents the significant items (discussed below) contributing to the change in earnings per share in the three and nine month periods ended September 30, 2008:

2008 Earnings Per Share vs. 2007

	Period Ended September 30,	
	QTD	**YTD**
2007	**$ 0.28**	**$ 1.04**
Electric Sales Margin	0.01	(0.03)
Gas Sales Margin	0.03	0.15
Usource Sales Margin	0.01	0.01
Operation & Maintenance Expense	(0.05)	0.12
Depreciation, Amortization & Other	---	(0.12)
Interest Expense, Net	(0.01)	(0.05)
2008	**$ 0.27**	**$ 1.12**

Unitil's total electric kilowatt-hour (kWh) sales decreased 2.0% and 2.1% in the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007. Natural gas sales in the three month period ended September 30, 2008 increased 5.7% compared to the same period in 2007 and decreased 0.5% in the nine month period ended September 30, 2008 compared to the same period in 2007. The lower kWh sales in 2008 compared to 2007 reflect milder summer weather in 2008 and lower average usage by the Company's customers reflecting a slowing economy and energy conservation. The increased natural gas sales in the three month period reflect increased consumption by Commercial and Industrial (C&I) customers for production operations. The lower natural gas sales in the nine month period reflect a milder winter heating season earlier this year and lower average usage by the Company's customers reflecting a slowing economy and energy conservation.

Electric sales margin increased $0.1 million in the three month period ended September 30, 2008 compared to the same period in 2007, reflecting higher electric base rates partially offset by lower sales volumes. For the nine month period ended September 30, 2008, electric sales margin decreased $0.3 million compared to the same period in 2007. The decrease in electric sales margin in the nine month period primarily reflects lower sales volumes, partially offset by higher electric base rates, implemented in March of 2008.

Gas sales margin increased $0.2 million and $1.3 million in the three and nine months ended September 30, 2008, respectively, compared to the same periods in 2007. The increase in the three month period reflects gas base rates implemented in November 2007 and higher natural gas sales to C&I customers. The increased sales margin in the nine month period reflects higher rates, partially offset by lower sales.

Usource revenues increased by $0.1 million and $0.1 million in the three and nine month periods ended September 30, 2008 compared to the same periods in 2007 reflecting higher revenues from energy brokering.

Operation & Maintenance (O&M) expenses increased $0.5 million for the three month period ended September 30, 2008 compared to the same period in 2007. The increase in the three month period reflects higher salary and benefit costs of $0.3 million, higher bad debt expenses of $0.2 million and higher utility operating costs of $0.2 million, partially offset by lower professional fees of $0.2 million. For the nine month period ended September 30, 2008, O&M expenses decreased $1.1 million compared to the same period in 2007, including a reduction of $2.8 million from the proceeds of an insurance settlement, lower utility operating costs of $0.1 million and lower professional fees of $0.1 million, partially offset by increases in salary and benefit costs of $1.5 million and higher bad debt expenses of $0.4 million.

Depreciation, Amortization & Other expenses decreased $0.1 million in the three month period ended September 30, 2008, reflecting lower amortization of information systems related costs and lower income tax expense in the current quarter compared to the same period in 2007, partially offset by higher depreciation on normal utility plant additions. For the nine month period ended September 30, 2008, Depreciation, Amortization & Other expenses increased $1.2 million, primarily reflecting the amortization, in the first quarter of 2008, of $0.7 million of natural gas inventory carrying costs deferred under a previous regulatory ruling and higher depreciation on normal utility plant additions.

Interest Expense, Net increased $0.1 million and $0.5 million for the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007, reflecting higher overall debt outstanding.

Also in the third quarter, the Unitil Corporation Board of Directors declared the regular quarterly dividend on the Company's common stock of $0.345 per share. This quarterly dividend results in a current effective annual dividend rate of $1.38 per share representing an unbroken record of quarterly dividend payments since trading began in Unitil's common stock.

A more detailed discussion of the Company's results of operations for the three and nine months ended September 30, 2008 and a period-to-period comparison of changes in financial position are presented below.

Balance Sheet

The Company's investment in Net Utility Plant increased by $9.4 million as of September 30, 2008 compared to September 30, 2007. This increase was due to capital expenditures related to UES' and FG&E's electric and gas distribution systems, including expenditures of approximately $0.5 million for the Company's Advanced Metering Infrastructure (AMI) project, which was substantially completed in the first quarter of 2008.

Regulatory Assets decreased by $30.5 million as of September 30, 2008 compared to September 30, 2007, primarily reflecting current year cost recoveries. A significant portion of this decrease is matched by a corresponding decrease of $20.0 million in Power Supply Contract Obligations. The remaining decrease primarily reflects lower levels of Regulatory Assets associated with retirement benefit obligations as well as recoveries of deferred charges (See "Regulatory Accounting" section of "Critical Accounting Policies").

Other Noncurrent Assets increased by $6.8 million as of September 30, 2008 compared to September 30, 2007, including the deferral of $3.9 million of transaction costs and $0.6 million of financing costs in connection with the Company's pending acquisition of Northern and Granite, discussed above, $1.6 million of pre-acquisition information system development costs and $0.7 million of other items unrelated to the acquisition.

Electric Sales, Revenues and Margin

Kilowatt-hour Sales – Unitil's total electric kWh sales decreased 2.0% and 2.1% in the three and nine month periods ended September 30, 2008, respectively compared to the same periods in 2007. Electric kWh sales to residential customers in the three and nine month periods ended September 30, 2008 decreased 1.9% and 1.8%, respectively, compared to the same periods in 2007 while sales to C&I customers decreased 2.0% and 2.3%, respectively, in those periods compared to the same periods in 2007. The lower electric kWh sales in 2008 compared to 2007 were driven by lower average usage per customer reflecting milder summer temperatures, a slowing economy and energy conservation.

The following table details total electric kWh sales for the three and nine months ended September 30, 2008 and 2007 by major customer class:

Electric kWh Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2008	2007	Change	% Change	**2008**	2007	Change	% Change
Residential	**176.3**	179.7	(3.4)	(1.9%)	**506.2**	515.6	(9.4)	(1.8%)
Commercial / Industrial	**279.4**	285.1	(5.7)	(2.0%)	**794.5**	813.2	(18.7)	(2.3%)
Total	**455.7**	464.8	(9.1)	(2.0%)	**1,300.7**	1,328.8	(28.1)	(2.1%)

Electric Operating Revenues and Sales Margin - The following table details total Electric Operating Revenues and Sales Margin for the three and nine month periods ended September 30, 2008 and 2007:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2008	2007	$ Change	% Change(1)	**2008**	2007	$ Change	% Change(1)
Electric Operating Revenues:								
Residential	**$ 30.9**	$ 28.6	$ 2.3	4.0%	**$ 87.0**	$ 87.2	$ (0.2)	(0.1%)
Commercial / Industrial	**32.7**	28.3	4.4	7.8%	**85.2**	84.1	1.1	0.6%
Total Electric Operating Revenues	**$ 63.6**	$ 56.9	$ 6.7	11.8%	**$ 172.2**	$ 171.3	$ 0.9	0.5%
Cost of Electric Sales:								
Purchased Electricity	**$ 48.7**	$ 41.9	$ 6.8	12.0%	**$ 128.4**	$ 126.4	$ 2.0	1.2%
Conservation & Load Management	**0.6**	0.8	(0.2)	(0.4%)	**2.0**	2.8	(0.8)	(0.5%)
Electric Sales Margin	**$ 14.3**	$ 14.2	$ 0.1	0.2%	**$ 41.8**	$ 42.1	$ (0.3)	(0.2%)

(1) Represents change as a percent of Total Electric Operating Revenues.

Total Electric Operating Revenues, increased by $6.7 million, or 11.8%, and $0.9 million, or 0.5%, in the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in the three month period reflects higher Purchased Electricity costs of $6.8 million and higher sales margin of $0.1 million, partially offset by lower C&LM revenues of $0.2 million. The net increase in Total Electric Operating Revenues in the nine month period reflects higher Purchased Electricity costs of $2.0 million, lower C&LM revenues of $0.8 million and lower sales margin of $0.3 million.

Purchased Electricity and C&LM revenues increased a net $6.6 million, or 11.6%, and $1.2 million, or 0.7%, of Total Electric Operating Revenues in the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The increase in the three month period primarily reflects higher electric commodity prices, partially offset by lower sales volumes. The increase in the nine month period reflects higher electric commodity prices, largely offset by lower sales volumes and lower spending on energy efficiency and conservation programs. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin increased $0.1 million in the three month period ended September 30, 2008 compared to the same period in 2007, reflecting higher electric base rates partially offset by lower sales volumes. For the nine month period ended September 30, 2008, electric sales margin decreased $0.3 million compared to the same period in 2007. The decrease in electric sales margin in the nine month period primarily reflects lower sales volumes, partially offset by higher electric base rates, implemented in March of 2008. Total electric kWh sales decreased 2.0% and 2.1% in the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007, driven by lower average usage per customer reflecting a slowing economy and energy conservation.

Gas Sales, Revenues and Margin

Therm Sales – Unitil's total therm sales of natural gas increased 5.7% in the three month period ended September 30, 2008 compared to the same period in 2007. Gas sales to residential customers in the three month period ended September 30, 2008 were flat compared to the same period in 2007 while sales to C&I customers increased 7.1% in that period compared to the same period in 2007. The increase in gas sales to C&I customers in the three month period reflects increased usage of natural gas in their production operations.

Total therm sales of natural gas in the nine month period ended September 30, 2008 decreased 0.5% compared to the same period in 2007. Gas sales to residential customers in the nine month period ended September 30, 2008 decreased 2.5% compared to the same period in 2007 while sales to C&I customers increased 0.7% in that period compared to the same period in 2007. The lower sales to residential customers in 2008 reflects a milder winter heating season earlier this year and lower average usage by our customers reflecting a slowing economy and energy conservation. The increase in gas sales to C&I customers in the nine month period reflects increased usage of natural gas in those customers' production operations.

The following table details total therm sales for the three and nine months ended September 30, 2008 and 2007 by major customer class:

Therm Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2008	2007	Change	% Change	**2008**	2007	Change	% Change
Residential	**0.7**	0.7	---	---	**7.7**	7.9	(0.2)	(2.5%)
Commercial / Industrial	**3.0**	2.8	0.2	7.1%	**13.9**	13.8	0.1	0.7%
Total	**3.7**	3.5	0.2	5.7%	**21.6**	21.7	(0.1)	(0.5%)

Gas Operating Revenues and Sales Margin – The following table details total Gas Operating Revenues and Sales Margin for the three and nine months ended September 30, 2008 and 2007:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2008	2007	$ Change	% Change[1]	**2008**	2007	$ Change	% Change[1]
Gas Operating Revenues:								
Residential	**$ 2.1**	$ 1.8	$ 0.3	7.7%	**$ 13.7**	$ 13.6	$ 0.1	0.4%
Commercial / Industrial	**2.3**	2.1	0.2	5.1%	**11.6**	10.9	0.7	2.9%
Total Gas Operating Revenues	**$ 4.4**	$ 3.9	$ 0.5	12.8%	**$ 25.3**	$ 24.5	$ 0.8	3.3%
Cost of Gas Sales:								
Purchased Gas	**$ 2.4**	$ 2.1	$ 0.3	7.7%	**$ 15.3**	$ 15.8	$ (0.5)	(2.0%)
Conservation & Load Management	**---**	---	---	---	**0.1**	0.1	---	---
Gas Sales Margin	**$ 2.0**	$ 1.8	$ 0.2	5.1%	**$ 9.9**	$ 8.6	$ 1.3	5.3%

[1] Represents change as a percent of Total Gas Operating Revenues.

Total Gas Operating Revenues increased $0.5 million, or 12.8%, and $0.8 million, or 3.3%, in the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007. Total Gas Operating Revenues include the recovery of the cost of gas sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in the three month period reflects higher Purchased Gas costs of $0.3 million and higher gas sales margin of $0.2 million. The net increase in Total Gas Operating Revenues in the nine month period reflects higher gas sales margin of $1.3 million, partially offset by lower Purchased Gas costs of $0.5 million.

Purchased Gas and C&LM revenues increased by $0.3 million, or 7.7% of Total Gas Operating Revenues in the three month period ended September 30, 2008 compared to the same period in 2007 and decreased $0.5 million, or 2.0% of Total Gas Operating Revenues in the nine month period ended September 30, 2008 compared to the same period in 2007. The increase in the three month period reflects higher sales volumes and higher natural gas commodity prices. The decrease in the nine month period reflects lower sales volumes and an increase in the amount of natural gas purchased by customers directly from third-party suppliers, partially offset by higher natural gas commodity prices. Purchased Gas revenues include the recovery of the cost of gas purchased and manufactured to supply the Company's total gas supply requirements as well as other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin increased $0.2 million and $1.3 million in the three and nine months ended September 30, 2008, respectively, compared to the same periods in 2007. The increase in the three month period reflects gas base rates implemented in November 2007 and higher natural gas sales to C&I customers. The increased gas sales margin in the nine month period reflects higher rates, partially offset by lower sales.

Other Operating Revenue

The following table details total Other Operating Revenue for the three and nine months ended September 30, 2008 and 2007:

Other Operating Revenue (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2008	2007	$ Change	% Change	**2008**	2007	$ Change	% Change
Other Operating Revenue	**$ 1.1**	$ 1.0	$ 0.1	10.0%	**$ 2.9**	$ 2.8	$ 0.1	3.6%
Total Other Operating Revenue	**$ 1.1**	$ 1.0	$ 0.1	10.0%	**$ 2.9**	$ 2.8	$ 0.1	3.6%

Total Other Operating Revenue increased by $0.1 million, or 10.0%, and $0.1 million, or 3.6%, in the three and nine month periods ended September 30, 2008 compared to the same periods in 2007. These increases reflect higher revenues from the Company's non-regulated energy brokering business, Usource.

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $6.8 million, or 16.2%, and $2.0 million, or 1.6%, in the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007. These increases reflect higher electric commodity prices, partially offset by lower sales volumes. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas expenses increased by $0.3 million, or 14.3%, in the three month period ended September 30, 2008 compared to the same period in 2007 and decreased $0.5 million, or 3.2% in the nine month period ended September 30, 2008 compared to the same period in 2007. The increase in the three month period reflects higher sales volumes and higher natural gas commodity prices. The decrease in the nine month period reflects lower sales volumes and an increase in the amount of natural gas purchased by customers directly from third-party suppliers, partially offset by higher natural gas commodity prices. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) – O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. O&M expenses increased $0.5 million for the three month period ended September 30, 2008 compared to the same period in 2007. The increase in the three month period reflects higher salary and benefit costs of $0.3 million, higher bad debt expenses of $0.2 million and higher utility operating costs of $0.2 million, partially offset by lower professional fees of $0.2 million. For the nine month period ended September 30, 2008, O&M expenses decreased $1.1 million compared to the same period in 2007, including a reduction of $2.8 million from the proceeds of an insurance settlement, lower utility operating costs of $0.1 million and lower professional fees of $0.1 million, partially offset by increases in salary and benefit costs of $1.5 million and higher bad debt expenses of $0.4 million.

Conservation & Load Management – C&LM expenses are associated with the development, management, and delivery of the Company's Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased $0.2 million, or 25.0% and $0.8 million, or 27.6%, in the three and nine month periods ended September 30, 2008 compared to the same periods in 2007. These changes reflect the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense increased by $0.1 million, or 2.2% and $0.9 million, or 6.7% in the three and nine month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The increase in the three month period primarily reflects higher depreciation on normal utility plant additions, partially offset by lower amortization of information systems related costs. The increase in the nine month period primarily reflects the amortization, in the first quarter of 2008, of $0.7 million of natural gas inventory carrying costs deferred under a previous regulatory ruling and higher depreciation on normal utility plant additions.

Local Property and Other Taxes - Local Property and Other Taxes increased by $0.1 million, or 7.7% and by $0.3 million, or 7.1% in the three and nine month periods ended September 30, 2008 compared to the same periods in 2007. These increases were due to higher property tax rates on increased property assessments and higher payroll taxes on higher compensation expenses.

Federal and State Income Taxes - Federal and State Income Taxes were lower by $0.3 million in the three month period ended September 30, 2008 compared to the same period in 2007 reflecting lower pre-tax earnings and a lower effective tax rate year over year due to the recognition of higher permanent book/tax differences, including higher tax credits and prior year tax return true-up adjustments, in the third quarter of 2008. Federal and State Income Taxes were lower by $0.2 million in the nine month period ended September 30, 2008 compared to the same period in 2007 reflecting a lower effective tax rate year over year due to the same items discussed above.

Other Non-operating Expenses

Other Non-operating Expenses were flat in the three month period ended September 30, 2008 compared to the same period in 2007 and increased by $0.2 million in the nine month period ended September 30, 2008 compared to the same period in 2007. The increase in the nine month period reflects an adjustment of $0.1 million in conjunction with the Company's electric base distribution rate increase in Massachusetts which was implemented in March, 2008.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company's retail distribution utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company's tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (Millions)	Three Months Ended September 30,			Nine Months Ended September 30,		
	2008	2007	Change	**2008**	2007	Change
Interest Expense						
Long-term Debt	$ 2.9	$ 2.9	$ ---	$ 8.6	$ 8.2	$ 0.4
Short-term Debt	0.1	0.1	---	0.5	0.8	(0.3)
Regulatory Liabilities	---	0.1	(0.1)	0.1	0.4	(0.3)
Subtotal Interest Expense	3.0	3.1	(0.1)	9.2	9.4	(0.2)
Interest Income						
Regulatory Assets	(0.6)	(0.7)	0.1	(1.9)	(2.2)	0.3
AFUDC[1] and Other	---	(0.1)	0.1	---	(0.4)	0.4
Subtotal Interest Income	(0.6)	(0.8)	0.2	(1.9)	(2.6)	0.7
Total Interest Expense, Net	$ 2.4	$ 2.3	$ 0.1	$ 7.3	$ 6.8	$ 0.5

[1] AFUDC – Allowance for Funds Used During Construction

Interest Expense, Net increased $0.1 million for the three month period ended September 30, 2008 compared to the same period in 2007. The increase in the three month period reflects lower Allowance for Funds Used During Construction (AFUDC) and interest earned on regulatory assets. For the nine month period ended September 30, 2008, Interest Expense, Net increased $0.5 million compared to the same period in 2007, reflecting higher interest expense associated with an increase in long-term debt outstanding and lower AFUDC and interest earned on regulatory assets compared to the prior period.

LIQUIDITY AND CAPITAL REQUIREMENTS

Sources of Capital

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company initially supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term nature of its utility assets.

The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including, but not limited to: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

At September 30, 2008, Unitil had $37.0 million in unsecured revolving lines of credit through two banks. The Company had short-term debt outstanding through bank borrowings of $21.7 million and $13.0 million at September 30, 2008 and 2007, respectively.

On February 15, 2008, the Company entered into a Stock Purchase Agreement with NiSource and Bay State to acquire all of the outstanding stock of Northern and Granite. The Company has a commitment letter to enter into a senior unsecured bridge facility, which the Company expects to use to finance this transaction. The Company anticipates either financing the initial acquisition or refinancing the bridge facility with the issuance of a combination of long-term debt and common equity securities. (See discussion on the pricing of the anticipated sale and issuance of long-term debt in the "Overview" section above and in Note 4.)

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiaries. The Company's policy is to limit these guarantees to the duration of the contracts, which range from less than one to thirteen months. As of September 30, 2008, there were approximately $6.0 million of guarantees outstanding and the longest term guarantee extends through October 31, 2009. The Company also agreed to guarantee the payment of principal and interest on the Granite notes, when they are issued, as discussed in the "Overview" section above and in Note 4.

Off-Balance Sheet Arrangements

There have been no material changes to the discussion of "Off-Balance Sheet Arrangements" included in Part II, Item 7 of the Company's Form 10-K for the year ended December 31, 2007, as filed with the Securities and Exchange Commission on February 12, 2008.

Cash Flows

The tables below summarize the major sources and uses of cash (in millions) for the nine months ended September 30, 2008 compared to the same period in 2007.

	Nine Months Ended September 30,	
	2008	2007
Cash Provided by Operating Activities	**$ 27.1**	$ 23.6

Cash Provided by Operating Activities - Cash Provided by Operating Activities was $27.1 million during the nine months ended September 30, 2008, an increase of $3.5 million over the comparable period in 2007. Cash flow from Net Income, adjusted for non-cash charges to depreciation, amortization and deferred taxes was $23.2 million and $16.9 million in the first nine months of 2008 and 2007, respectively. Changes in Current Assets and Liabilities (working capital) provided $1.2 million and $3.5 million in cash flow in the 2008 and 2007 nine-month periods. Deferred Restructuring Charges provided $2.4 million and $1.5 million in cash in the first nine months of 2008 and the same period in 2007, respectively. All other items resulted in net sources of cash of $0.3 million and $1.7 million in the first nine months of 2008 and 2007, respectively.

	Nine Months Ended September 30,	
	2008	2007
Cash (Used in) Investing Activities	**$ (20.6)**	$ (25.9)

Cash (Used in) Investing Activities - Cash (Used in) Investing Activities was $20.6 million for the nine months ended September 30, 2008, a decrease in capital spending of $5.3 million over the comparable period in 2007. This is mainly due to the funding in 2007 and the completion in 2008 of the Company's Advanced Metering

Infrastructure (AMI) project. In the first nine months of 2007, capital expenditures included approximately $5.9 million of cash outlays for investment in the AMI project.

	Nine Months Ended September 30,	
	2008	2007
Cash Provided by (Used in) Financing Activities	**$ (6.1)**	$ 1.9

Cash Provided by (Used in) Financing Activities - Cash (Used in) Financing Activities was $6.1 million in the nine months ended September 30, 2008. Uses of cash primarily reflect Unitil's regular quarterly dividend payments on Common and Preferred Stock, expenditures related to the Company's acquisition of Northern and Granite, discussed above, and the scheduled repayment of long-term debt. Proceeds from the issuance of Common Stock through the Company's stock plans and additional short-term debt provided $3.6 million of cash in 2008. In the second quarter of 2007, Unitil received cash proceeds of $20.0 million from the issuance of Senior Long-term Notes, which were used to pay down short-term debt.

CRITICAL ACCOUNTING POLICIES

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to Note 1 to the Consolidated Financial Statements in the Company's Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 12, 2008.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas by the retail distribution utilities: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDPU and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement on Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided below. The Company receives a return on investment on its regulated assets for which a cash outflow has been made.

Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. The Company believes it is probable that its regulated distribution utilities will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDPU and NHPUC.

Regulatory Assets consist of the following (millions)	September 30, 2008	September 30, 2007	December 31, 2007
Power Supply Buyout Obligations	**$ 57.7**	$ 77.7	$ 72.7
Deferred Restructuring Costs	**28.1**	29.5	30.5
Generation-related Assets	**1.0**	1.8	1.6
Subtotal – Restructuring Related Items	**86.8**	109.0	104.8
Retirement Benefit Obligations	**35.2**	37.3	35.1
Income Taxes	**13.4**	17.9	14.6
Environmental Obligations	**11.6**	13.1	13.1
Other	**3.3**	3.5	2.9
Total Regulatory Assets	**$ 150.3**	$ 180.8	$ 170.5

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In the Company's opinion, its regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates and charges approved by federal and state regulatory commissions. Revenues related to the sale of electric and gas service are recorded when service is rendered or energy is delivered to customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a provision for doubtful accounts each month. The amount of the monthly provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis, including expected fuel assistance payments from governmental authorities and the level of customers enrolling in payment plans with the Company. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the provision for doubtful accounts to maintain an adequate Allowance for Doubtful Accounts balance. It has been the Company's experience that the assumptions it has used in evaluating the adequacy of the Allowance for Doubtful Accounts have proven to be reasonably accurate.

Retirement Benefit Obligations - The Company sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company

sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", (SFAS No. 158), an amendment of SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions" and SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." SFAS No. 158 requires companies to record on their balance sheets as an asset or liability the overfunded or underfunded status of their retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric and gas retail rates.

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The Company's RBO are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future costs. The Company's RBO may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the Company's RBO.

If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's financial statements. The discount rate assumptions used in determining retirement plan costs and retirement plan obligations are based on a market average of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For the years ended December 31, 2007 and 2006, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Benefit Cost for the Pension Plan. For the years ended December 31, 2007 and 2006, a 1.0% increase in the assumption of health care cost trend rates would have resulted in increases in the Net Periodic Benefit Cost for the PBOP Plan of $690,000 and $683,000, respectively. Similarly, a 1.0% decrease in the assumption of health care cost trend rates for those same time periods would have resulted in decreases in the Net Periodic Benefit Cost for the PBOP Plan of $539,000 and $530,000, respectively. (See Note 8)

Income Taxes - Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's consolidated balance sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with FASB Statement No. 109, "Accounting for Income Taxes" (SFAS No. 109) and under FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109.

Depreciation - Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements.

Commitments and Contingencies - The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5, "Accounting for Contingencies". SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of September 30, 2008, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Pronouncements" in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

LABOR RELATIONS

As of September 30, 2008, there were 305 employees of the Company, of which 82 employees are represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company's debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company's short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company's interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company's short-term borrowings for the three months ended September 30, 2008 and 2007 were 3.03% and 5.71%, respectively. The average interest rates on the Company's short-term borrowings for the nine months ended September 30, 2008 and 2007 were 3.28% and 5.75%, respectively.

MARKET RISK

Although Unitil's retail distribution utilities are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of electric power and natural gas supply costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, further reduced its exposure to commodity risk.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF EARNINGS
(Millions except common shares and per share data)
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	**2008**	2007
Operating Revenues				
Electric	**$ 63.6**	$ 56.9	**$ 172.2**	$ 171.3
Gas	**4.4**	3.9	**25.3**	24.5
Other	**1.1**	1.0	**2.9**	2.8
Total Operating Revenues	**69.1**	61.8	**200.4**	198.6
Operating Expenses				
Purchased Electricity	**48.7**	41.9	**128.4**	126.4
Purchased Gas	**2.4**	2.1	**15.3**	15.8
Operation and Maintenance	**7.0**	6.5	**18.7**	19.8
Conservation & Load Management	**0.6**	0.8	**2.1**	2.9
Depreciation and Amortization	**4.6**	4.5	**14.3**	13.4
Provisions for Taxes:				
Local Property and Other	**1.4**	1.3	**4.5**	4.2
Federal and State Income	**0.5**	0.8	**3.0**	3.2
Total Operating Expenses	**65.2**	57.9	**186.3**	185.7
Operating Income	**3.9**	3.9	**14.1**	12.9
Non-Operating Expenses	**---**	---	**0.3**	0.1
Income Before Interest Expense	**3.9**	3.9	**13.8**	12.8
Interest Expense, Net	**2.4**	2.3	**7.3**	6.8
Net Income	**1.5**	1.6	**6.5**	6.0
Less: Dividends on Preferred Stock	**---**	---	**0.1**	0.1
Earnings Applicable to Common Shareholders	**$ 1.5**	$ 1.6	**$ 6.4**	$ 5.9
Average Common Shares Outstanding – Basic (000's)	**5,745**	5,659	**5,733**	5,643
Average Common Shares Outstanding - Diluted (000's)	**5,748**	5,668	**5,738**	5,659
Earnings Per Common Share (Basic and Diluted)	**$ 0.27**	$ 0.28	**$ 1.12**	$ 1.04
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.38**	$ 1.38

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Millions)

	(UNAUDITED) September 30, 2008	(UNAUDITED) September 30, 2007	December 31, 2007
ASSETS:			
Utility Plant:			
Electric	**$ 275.5**	$ 260.5	$ 266.2
Gas	**71.3**	65.5	67.8
Common	**27.3**	25.8	26.2
Construction Work in Progress	**10.9**	24.2	20.3
Total Utility Plant	**385.0**	376.0	380.5
Less: Accumulated Depreciation	**129.0**	129.4	131.6
Net Utility Plant	**256.0**	246.6	248.9
Current Assets:			
Cash	**5.0**	4.2	4.6
Accounts Receivable – Net of Allowance for Doubtful Accounts of $1.3, $2.1 and $1.3	**23.2**	22.8	24.9
Accrued Revenue	**14.7**	9.5	12.7
Refundable Taxes	**0.4**	---	0.7
Materials and Supplies	**5.1**	4.4	4.5
Prepayments and Other	**1.1**	1.2	1.5
Total Current Assets	**49.5**	42.1	48.9
Noncurrent Assets:			
Regulatory Assets	**150.3**	180.8	170.5
Debt Issuance Costs, net	**2.7**	2.8	2.8
Other Noncurrent Assets	**9.0**	2.2	3.5
Total Noncurrent Assets	**162.0**	185.8	176.8
TOTAL	**$ 467.5**	$ 474.5	$ 474.6

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(Millions)

	(UNAUDITED) September 30, 2008	(UNAUDITED) September 30, 2007	December 31, 2007
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 99.9**	$ 97.4	$ 100.4
Preferred Stock, Non-Redeemable, Non-Cumulative	**0.2**	0.2	0.2
Preferred Stock, Redeemable, Cumulative	**1.8**	1.8	1.9
Long-Term Debt, Less Current Portion	**159.4**	159.8	159.6
Total Capitalization	**261.3**	259.2	262.1
Current Liabilities:			
Long-Term Debt, Current Portion	**0.4**	0.4	0.4
Capitalized Leases, Current Portion	**0.2**	0.3	0.3
Short-Term Debt	**21.7**	13.0	18.8
Accounts Payable	**18.0**	15.0	17.6
Taxes Payable	**---**	3.5	---
Interest and Dividends Payable	**5.0**	5.0	1.9
Other Current Liabilities	**5.0**	4.6	5.1
Total Current Liabilities	**50.3**	41.8	44.1
Deferred Income Taxes	**34.4**	31.4	33.4
Noncurrent Liabilities:			
Power Supply Contract Obligations	**57.7**	77.7	72.7
Retirement Benefit Obligations	**49.5**	50.8	48.2
Environmental Obligations	**12.0**	12.0	12.0
Capitalized Leases, Less Current Portion	**0.4**	0.5	0.5
Other Noncurrent Liabilities	**1.9**	1.1	1.6
Total Noncurrent Liabilities	**121.5**	142.1	135.0
TOTAL	**$ 467.5**	$ 474.5	$ 474.6

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(UNAUDITED)

	Nine Months Ended September 30,	
	2008	2007
Operating Activities:		
Net Income	**$ 6.5**	$ 6.0
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**14.3**	13.4
Deferred Taxes	**2.4**	(2.5)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**1.7**	(0.3)
Accrued Revenue	**(2.0)**	4.3
Accounts Payable	**0.4**	(4.8)
Taxes Payable	**0.3**	2.6
All other Current Assets and Liabilities	**0.8**	1.7
Deferred Restructuring Charges	**2.4**	1.5
Other, net	**0.3**	1.7
Cash Provided by Operating Activities	**27.1**	23.6
Investing Activities:		
Property, Plant and Equipment Additions	**(20.6)**	(25.9)
Cash (Used in) Investing Activities	**(20.6)**	(25.9)
Financing Activities:		
Proceeds From (Repayment of) Short-Term Debt, net	**2.9**	(13.0)
Proceeds From Issuance of Long-Term Debt	**---**	20.0
Repayment of Long-Term Debt	**(0.2)**	(0.1)
Dividends Paid	**(6.1)**	(6.0)
Issuance of Common Stock	**0.7**	1.3
Retirement of Preferred Stock	**---**	(0.1)
Acquisition-Related Expenditures	**(3.3)**	---
Other, net	**(0.1)**	(0.2)
Cash (Used in) Provided by Financing Activities	**(6.1)**	1.9
Net Increase (Decrease) in Cash	**0.4**	(0.4)
Cash at Beginning of Period	**4.6**	4.6
Cash at End of Period	**$ 5.0**	$ 4.2
Supplemental Cash Flow Information:		
Interest Paid	**$ 8.0**	$ 7.6
Income Taxes Paid	**$ 0.5**	$ 3.3

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and nine months ended September 30, 2008 are not necessarily indicative of results to be expected for the year ending December 31, 2008. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2007, as filed with the SEC on February 12, 2008, for a description of the Company's Basis of Presentation.

Nature of Operations - Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned non-regulated subsidiary. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements – On September 12, 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. FAS 133-1 and FIN 45-4, "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities", (SFAS No. 133) and FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others", (FIN 45); and Clarification of the Effective Date of FASB Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" (SFAS No. 161)", (FSP FAS 133-1 and FIN 45-4). FSP FAS 133-1 and FIN 45-4 is effective for reporting periods ending after November 15, 2008, with early adoption permitted. FSP FAS 133-1 and FIN 45-4 (i) amends SFAS No. 133 to require disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument, (ii) amends FIN 45 to require an additional disclosure about the current status of the payment/performance risk of a guarantee, and (iii) clarifies the

FASB's intent about the effective date of SFAS No. 161. The Company adopted FSP FAS 133-1 and FIN 45-4 and there was no impact on its financial statements.

In May 2008, the FASB issued FASB Statement No. 162, "The Hierarchy of Generally Accepted Accounting Principles", (SFAS No. 162), effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board's amendments to AU Section 411. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States. The Company will adopt SFAS No. 162 when it is approved and does not expect it to have any impact on its financial statements.

In March 2008, the FASB issued SFAS No. 161, effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption allowed. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of an entity's use of derivative instruments and the effect of those derivative instruments on an entity's financial statements. The Company adopted SFAS No. 161 and there was no impact on its financial statements.

In December 2007, the FASB issued FASB Statement No. 141 (Revised 2007), "Business Combinations" (SFAS No. 141R), effective prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141R establishes principles and requirements on how an acquirer recognizes and measures in its financial statements identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree, goodwill or gain from a bargain purchase and accounting for transaction costs. Additionally, SFAS No. 141R determines what information must be disclosed to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The Company will adopt SFAS No. 141R upon its effective date and expects the adoption to affect any business combinations effected on or subsequent to that date.

In September 2006, the FASB issued FASB Statement No. 157, "Fair Value Measurements", (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Certain requirements of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS No. 157 has been deferred for one year by the FASB. The Company adopted the sections of SFAS No. 157 which are effective for fiscal years beginning after November 15, 2007 and there was no additional impact on the Company's Consolidated Financial Statements. The Company's fixed rate long-term debt falls under the fair value reporting requirements of SFAS No. 157. Accordingly, the Company has estimated the fair value of its long-term debt as of September 30, 2008 based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities (See Note 4). The Company does not expect that the adoption of the deferred sections of SFAS No. 157 will have an impact on the Company's Consolidated Financial Statements.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
09/25/08	10/31/08	10/17/08	$ 0.345
06/19/08	08/15/08	08/01/08	$ 0.345
03/20/08	05/15/08	05/01/08	$ 0.345
01/17/08	02/15/08	02/01/08	$ 0.345
09/13/07	11/15/07	11/01/07	$ 0.345
06/21/07	08/15/07	08/01/07	$ 0.345
03/22/07	05/15/07	05/01/07	$ 0.345
01/18/07	02/15/07	02/01/07	$ 0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

As of August 21, 2008 the Company's Common Stock began trading on the New York Stock Exchange and ceased trading on the American Stock Exchange. The Company's Common Stock will continue to trade under its current symbol, "UTL".

On September 10, 2008, the Company's shareholders, at a Special Meeting of Shareholders, approved an increase in the authorized shares of the Company's Common Stock. Shareholders approved an amendment to the Company's Articles of Incorporation to increase the authorized number of shares of the Company's Common Stock, from 8,000,000 shares to 16,000,000 shares in the aggregate. Of the 8,000,000 additional shares of newly authorized Common Stock, the Company expects to issue and sell up to 4,000,000 shares in a public offering to partially finance the acquisition of Northern Utilities, Inc. and Granite State Gas Transmission, Inc., discussed below in Note 6. The Company had 5,781,025, 5,730,395, and 5,740,023 of common shares outstanding at September 30, 2008, September 30, 2007 and December 31, 2007, respectively.

During the first nine months of 2008, the Company sold 22,462 shares of its Common Stock, at an average price of $27.43 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $616,000 were used to reduce short-term borrowings.

During the first nine months of 2007, the Company sold 28,675 shares of its Common Stock, at an average price of $27.65 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $793,000 were used to reduce short-term borrowings.

Also, in the second quarter of 2008, the Company issued and sold 3,000 shares of its Common Stock, at an average price of $24.63 per share, in connection with the exercise of stock options under the Unitil Corporation 1998 Stock Option Plan (1998 Plan). Net proceeds of $73,875 were used by the Company to reduce short-term borrowings. As disclosed in Note 2 to the Company's Form 10-K for the year ended December 31, 2007, the 1998 Plan became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, were determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vested over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's Common Stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. This plan was terminated on January 16, 2003. There was no compensation expense associated with this plan in 2008 and 2007. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of options will be made under this plan. As of September 30, 2008, there are 104,000 options vested and exercisable outstanding.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company's shareholders. On February 6, 2008, 15,540 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $445,998. Compensation expense associated with shares issued under the Plan is recognized ratably as the shares vest and was $0.4 million and $0.3 million for nine months ended September 30, 2008 and 2007, respectively. At September 30, 2008, there was approximately $0.9 million of total unrecognized compensation cost related to non-vested shares under the Plan which is expected to be recognized over approximately 2.6 years as the shares vest. During 2008, 11,249 restricted shares vested. As of September 30, 2008 there were 32,218 unvested restricted shares.

Details on preferred stock at September 30, 2008, September 30, 2007 and December 31, 2007 are shown below:

(Amounts in Millions)

	(Unaudited) September 30,		December 31,
	2008	2007	2007
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 0.2**	$ 0.2	$ 0.2
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**0.8**	0.8	0.9
8.00% Series, $100 Par Value	**1.0**	1.0	1.0
Total Preferred Stock	**$ 2.0**	$ 2.0	$ 2.1

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at September 30, 2008, September 30, 2007 and December 31, 2007 are shown below:

(Amounts in Millions)

	(Unaudited) September 30,		December 31,
	2008	2007	2007
Unitil Corporation Senior Notes:			
6.33% Notes, Due May 1, 2022	**$ 20.0**	$ 20.0	$ 20.0
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**15.0**	15.0	15.0
6.96% Series, Due September 1, 2028	**20.0**	20.0	20.0
8.00% Series, Due May 1, 2031	**15.0**	15.0	15.0
6.32% Series, Due September 15, 2036	**15.0**	15.0	15.0
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19.0**	19.0	19.0
7.37% Notes, Due January 15, 2029	**12.0**	12.0	12.0
7.98% Notes, Due June 1, 2031	**14.0**	14.0	14.0
6.79% Notes, Due October 15, 2025	**10.0**	10.0	10.0
5.90% Notes, Due December 15, 2030	**15.0**	15.0	15.0
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**4.8**	5.2	5.0
Total Long-Term Debt	**159.8**	160.2	160.0
Less: Current Portion	**0.4**	0.4	0.4
Total Long-term Debt, Less Current Portion	**$ 159.4**	$ 159.8	$ 159.6

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at September 30, 2008 is estimated to be approximately $158 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, the Company believes that there is no active market in the Company's debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2008 there are $6 million of guarantees outstanding and these guarantees extend through October 31, 2009. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

On September 12, 2008, in connection with the Company's acquisition of Northern Utilities, Inc. and Granite State Gas Transmission, Inc. (See Note 6), the Company priced the anticipated sale and issuance of $80.0 million aggregate principal amount of senior unsecured notes by Northern and $10.0 million aggregate principal amount of senior unsecured notes by Granite. The notes consist of:

(iv) $30.0 million aggregate principal amount of 6.95% senior unsecured notes of Northern, which are due in 2018;

(v) $50.0 million aggregate principal amount of 7.72% senior unsecured notes of Northern, which are due in 2038; and

(vi) $10.0 million aggregate principal amount of 7.15% senior unsecured notes of Granite, which are due in 2018.

The Company agreed to guarantee the payment of principal and interest on the Granite notes.

The Company plans to use the proceeds from the sale and issuance of the notes to repay all amounts outstanding under a bridge credit facility that will used to partially finance the acquisitions of Northern and Granite. The Company expects to close the sale and issuance of the notes promptly after the closing of the acquisitions.

The sale and issuance of the notes (i) is subject to the execution of definitive note purchase agreements by Northern, Granite and the prospective purchasers of the notes and satisfaction of closing conditions, (ii) will not be, and has not been, registered under the Securities Act of 1933 and the notes may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements and (iii) is not conditioned upon the closing of the offering of the Company's common stock, as described above. The Company has received the required regulatory approvals from the Public Utilities Commissions in New Hampshire and Maine for these debt issuances.

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and nine months ended September 30, 2008 and September 30, 2007 (Millions):

Three Months Ended:	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
September 30, 2008					
Revenues	**$ 63.6**	**$ 4.4**	**$ ---**	**$ 1.1**	**$ 69.1**
Segment Profit (Loss)	**1.9**	**(0.6)**	**---**	**0.2**	**1.5**
Capital Expenditures	**6.3**	**2.6**	**1.5**	**---**	**10.4**
September 30, 2007					
Revenues	$ 56.9	$ 3.9	$ ---	$ 1.0	$ 61.8
Segment Profit (Loss)	2.3	(0.7)	(0.1)	0.1	1.6
Capital Expenditures	4.7	1.7	(0.1)	---	6.3
Nine Months Ended:					
September 30, 2008					
Revenues	**$ 172.2**	**$ 25.3**	**$ ---**	**$ 2.9**	**$ 200.4**
Segment Profit (Loss)	**4.4**	**1.9**	**(0.2)**	**0.3**	**6.4**
Capital Expenditures	**15.9**	**3.1**	**1.6**	**---**	**20.6**
Segment Assets	**329.8**	**106.5**	**30.2**	**1.0**	**467.5**
September 30, 2007					
Revenues	$ 171.3	$ 24.5	$ ---	$ 2.8	$ 198.6
Segment Profit (Loss)	5.7	---	---	0.2	5.9
Capital Expenditures	21.8	3.9	0.2	---	25.9
Segment Assets	339.0	110.2	24.4	0.9	474.5

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2007 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 12, 2008.

FG&E – Electric Division – On December 3, 2007, FG&E submitted its annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan (the Annual Reconciliation Filing). The rates were approved effective January 1, 2008, subject to reconciliation pursuant to the MDPU's investigation. On June 6, 2008, FG&E submitted a revised Transition Charge reducing the recovery of net costs associated with the sale of Wyman 4 by $36,762 pursuant to an agreement with the Attorney General. This filing was approved on August 19, 2008.

FG&E – Other – On June 22, 2007, the MDPU opened an inquiry into revenue decoupling for gas and electric distribution utilities, generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's distribution revenues on sales. Revenue decoupling is intended to remove the disincentive a utility has to administer and promote customer efforts to reduce energy consumption and demand or to install distributed generation to displace electricity delivered by the utility. On July 16, 2008, the MDPU issued an order establishing a comprehensive plan for decoupling to be adopted by gas and electric distribution utilities on a going-forward basis. Company specific rate cases will be required. Lost base revenue recovery associated with incremental energy efficiency savings will be allowed through 2012 consistent with the MDPU's expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012. Within 45 days of this order, each distribution company was to notify the MDPU of when the company expects to file a rate case to implement decoupling. FG&E notified the MDPU that it will be prepared to file rate cases for each of its divisions by the third quarter of 2009, based upon a calendar 2008 test year, along with a comprehensive decoupling proposal and associated base rate adjustment mechanism. This matter remains pending before the MDPU.

On July 2, 2008, Massachusetts Senate Bill No. 2768 (the "Green Communities Act") was signed into law. The Green Communities Act is intended to increase energy efficiency, update the renewable energy portfolio standard, increase public oversight of utilities, increase service quality of power companies, assist low-income energy customers, and increase the use of renewable generation and energy efficiency products. The Act requires electric companies to boost investment in energy efficiency measures that reduce energy demand and deliver savings to customers; provides a new funding source for efficiency measures through the auction of pollution allowances by power plants through the Regional Greenhouse Gas Initiative; creates stronger incentives for the development of renewable energy, like wind and solar, by requiring 15 percent of electricity to be supplied by new green power facilities by 2020 and establishing a pilot program for utilities to enter into long-term contracts with renewable energy projects; expressly authorizes cities and towns to own renewable energy facilities; and encourages green building design through updated codes, training and assistance. The MDPU has begun to initiate regulatory proceedings to implement various sections of the Act. The impact of any new measures to be required of FG&E in compliance with the Act cannot be estimated at this time.

UES – In July, 2008, the State of New Hampshire passed a law that allows electric utilities to make investments in distributed energy resources including energy efficiency and demand reduction technologies as well as clean cogeneration and renewable generation. In June, 2008, The State of New Hampshire also passed a law approving state participation in the Regional Greenhouse Gas Initiative (RGGI). The RGGI program begins in 2009 and requires large electric generators in 10 northeast and mid-atlantic states to purchase allowances for their carbon emissions. These allowances are being sold through a regional auction process and the funds will be used by the states for investments in energy efficiency and alternative energy.

On March 14, 2008, UES made its annual reconciliation and rate filing with the NHPUC under its restructuring plan, for rates effective May 1, 2008, including reconciliation of prior year costs and revenues, power supply and power supply-related stranded costs. The filing was approved on April 23, 2008. On July 9, 2008, UES proposed an increase to its External Delivery Charge, effective September 1, 2008, reflecting higher transmission costs. The filing was approved on August 29, 2008.

On June 22, 2007, the NHPUC issued an order in its investigation into implementation of the federal Energy Policy Act of 2005 regarding the adoption of standards for time-based metering and interconnection. On August 31, 2007, the NHPUC issued an order on motion for rehearing, staying the June 22, 2007 order pending hearing and reconsideration of the issues. An order following rehearing was issued on January 22, 2008 finding that it is appropriate to implement some form of time-based metering standards and ordering that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes shall be determined in separate proceedings to be initiated by the Commission. In a decision issued on September 15, 2008, the NHPUC ordered the establishment of a working group to facilitate the evaluation and implementation of advanced metering infrastructure and time-based rates and that such working group make a report to the Commission by December 1, 2008 with regard to next steps toward utility specific cost-benefit analyses regarding such implementation. The Commission also found that additional review of the energy standards for net metering, fuel diversity and fossil fuel generation efficiency as proposed in the Energy Policy Act of 2005 is not required due to action of the NH legislature and the Commission in adopting comparable standards.

On May 14, 2007, the NHPUC issued an order opening an investigation into the merits of instituting appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency. This matter is pending before the NHPUC.

Acquisition of Northern Utilities Inc. and Granite State Gas Transmission, Inc.: On February 15, 2008, the Company entered into a Stock Purchase Agreement with NiSource, Inc. (NiSource) and Bay State Gas Company (Bay State, which is a wholly owned utility subsidiary of NiSource), to acquire all of the outstanding stock of Northern Utilities, Inc. (Northern), and Granite State Gas Transmission, Inc. (Granite) for $160 million in cash, which amount is subject to a working capital adjustment. The transaction is expected to be financed initially with proceeds from newly issued common stock together with a bridge credit facility. In the event that the equity offering is delayed until after the transaction closes, the Company may initially finance the transaction entirely with the bridge facility. The Company expects to repay the bridge facility as soon as practical after the transaction closes using the proceeds from the issuance of notes and newly issued common stock.

On March 31, 2008, Unitil and Northern filed joint petitions and supporting testimony with the Maine Public Utilities Commission (MPUC) and the NHPUC requesting approval of the acquisitions. Subsequently, on May 30, 2008, Unitil and Northern filed joint petitions before both the NHPUC and MPUC requesting authority for Northern to issue unsecured long term debt to finance the acquisition of Northern by Unitil. In August, 2008, unopposed stipulation agreements resolving all outstanding issues and recommending approval of the acquisition and the financing petitions were filed with the MPUC and the NHPUC on behalf of Unitil, Northern and the active parties to the respective Maine and New Hampshire proceedings.

On October 10, 2008, the NHPUC issued orders approving the stipulation agreement and the financing petition, and authorizing the acquisition of Northern by Unitil.

On October 6, 2008, the MPUC publicly deliberated the matter and voted to approve the joint petition and stipulation agreement with conditions, subject to its issuance of a final written order. On October 22, 2008, the MPUC issued its written order approving the stipulation agreement and authorizing the acquisition of Northern by Unitil, subject to several conditions. Based on its review of the written order, Unitil expects to file along with Northern, a motion for reconsideration of the order on narrow grounds requesting clarification and/or modification of conditions of approval contained in the order. These conditions would potentially contravene the allocation of risks agreed to by the parties in the stipulation agreement and underlying Stock Purchase Agreement with regard to several pending regulatory safety and compliance proceedings involving Northern. At this time, Unitil can not predict what changes, if any, the MPUC's reconsideration and continued deliberation of this matter will have on its order or the unopposed stipulation agreement of the parties in this proceeding.

As a result of statutory changes in Massachusetts (see discussion of "Green Communities Act," above), on August 13, 2008, Unitil and Bay State also filed a joint petition with the MDPU requesting an advisory ruling that Massachusetts law is not applicable to the proposed transaction, or, in the alternative, that it approve the transaction as consistent with the public interest. The Massachusetts Attorney General has asserted that Massachusetts law grants the MDPU jurisdiction to review the transaction, and argues that Bay State's customers will be harmed by the sale. Unitil and Bay State dispute the Attorney General's assertions. On October 1, 2008, a hearing on the joint petition was held before the MDPU, and on October 10 and October 17 the Parties to the proceeding filed their Initial and Reply Briefs, respectively. The Company has requested a final order from the MDPU on or before November 3, 2008, to allow the Company to proceed with the financing and closing of the transaction in the fourth quarter of 2008. The joint petition remains under active consideration by the MDPU.

As of September 30, 2008, the Company has deferred $3.9 million of transaction costs and $0.6 million of financing costs in connection with the Company's pending acquisition of Northern and Granite, discussed above, and $1.6 million of pre-acquisition system development costs. The transaction is expected to close by the end of 2008, subject to completion of the regulatory review process.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2007 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 12, 2008.

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company believes it is in compliance in all material respects with all applicable environmental and safety laws and regulations, and the Company believes that as of September 30, 2008, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Included on the Company's Consolidated Balance Sheet at September 30, 2008, in Environmental Obligations is $12.0 million related to estimated future clean up costs for permanent remediation of a former manufactured gas plant site at Sawyer Passway, located in Fitchburg, Massachusetts. A corresponding regulatory asset was recorded to reflect the future rate recovery of these costs. As noted above, please refer to Note 5 to the financial statements in Item 8 of Part II of the Company's Form 10-K for December 31, 2007 for additional information. The Company received an insurance settlement during the first quarter of 2008 associated with environmental remediation costs. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan covering substantially all of its employees. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) – The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) – The SERP is an unfunded retirement plan, with participation limited to executives selected by the Board of Directors.

The following table includes the key weighted average assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan Costs	**2008**	2007
Discount Rate	**6.00%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Expected Long-term rate of return on plan assets	**8.50%**	8.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2017**	2016

Used to Determine Benefit Obligations:	**2008**	2007
Discount Rate	**6.00%**	5.50%
Rate of Compensation Increase	**3.50%**	3.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2017**	2016

The following tables provide the components of the Company's Retirement plan costs ($000's):

	Pension Plan		PBOP Plan		SERP	
Three Months Ended September 30,	**2008**	2007	**2008**	2007	**2008**	2007
Service Cost	**$ 488**	$ 492	**$ 355**	$ 358	**$ 37**	$ 40
Interest Cost		834	**559**	514	**31**	29
Expected Return on Plan Assets	**(1,093)**	(1,050)	**(82)**	(61)	**---**	---
Prior Service Cost Amortization	**27**	27	**341**	341	**1**	---
Transition Obligation Amortization	**---**	---	**6**	5	**---**	---
Actuarial Loss Amortization	**318**	336	**---**	17	**6**	11
Sub-total	**684**	639	**1,179**	1,174	**75**	80
Amounts Capitalized and Deferred	**(226)**	(215)	**(496)**	(489)	**---**	---
Net Periodic Benefit Cost Recognized	**$ 458**	$ 424	**$ 683**	$ 685	**$ 75**	$ 80

	Pension Plan		PBOP Plan		SERP	
Nine Months Ended September 30,	**2008**	2007	**2008**	2007	**2008**	2007
Service Cost	**$ 1,464**	$ 1,476	**$ 1,065**	$ 1,073	**$ 111**	$ 122
Interest Cost	**2,831**	2,502	**1,677**	1,543	**94**	88
Expected Return on Plan Assets	**(3,280)**	(3,146)	**(245)**	(184)	**---**	---
Prior Service Cost Amortization	**81**	80	**1,022**	1,020	**1**	(1)
Transition Obligation Amortization	**---**	---	**17**	16	**---**	---
Actuarial Loss Amortization	**956**	1,008	**---**	52	**18**	33
Sub-total	**2,052**	1,920	**3,536**	3,520	**224**	242
Amounts Capitalized and Deferred	**(673)**	(651)	**(1,448)**	(1,506)	**---**	---
Net Periodic Benefit Cost Recognized	**$ 1,379**	$ 1,269	**$ 2,088**	$ 2,014	**$ 224**	$ 242

Employer Contributions

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan's liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. As of September 30, 2008, the Company has funded $2.8 million to fund its Pension Plan in 2008 and does not anticipate making additional contributions in 2008.

As of September 30, 2008, the Company had made $1.6 million and $46,000 of contributions to the PBOP and SERP Plans, respectively, in 2008. The Company presently anticipates contributing an additional $1.1 million and $13,000 to the PBOP and SERP Plans, respectively, in 2008.

NOTE 9: INCOME TAXES

The Company bills its customers sales tax in Massachusetts and consumption tax in New Hampshire. These taxes are remitted to the appropriate departments of revenue in each state and are excluded from revenues on the Company's Consolidated Statements of Earnings.

The Company evaluated its tax positions at December 31, 2007, and at each interim reporting date in the period ended September 30, 2008 in accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), an interpretation of FAS 109, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any unrecognized tax liabilities or assets as defined by FIN 48 is required. The Company does not have any unrecognized tax positions for which it is reasonably possible that the total amounts recognized will significantly change within the next 12 months. The Company remains subject to examination by Federal, Massachusetts and New Hampshire tax authorities for the tax periods ended December 31, 2005; December 31, 2006; and December 31, 2007. Income tax filings for the year ended December 31, 2007 have been filed with the Internal Revenue Service. The Company classifies penalty and interest expense related to income tax liabilities as an income tax expense. There are no interest and penalties recognized in the statement of earnings or accrued on the balance sheets.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Unaudited Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company's Form 10-K for the year-ended December 31, 2007 as filed with the Securities and Exchange Commission on February 12, 2008, other than the risks associated with the Company's recently announced acquisition of Northern and Granite and the risks associated with the recent distress in the financial markets, as discussed in the Cautionary Statement section of Part I, Item 2 of this Quarterly Report on Form 10-Q for the quarter ended September 30, 2008.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered equity securities by the Company for the fiscal period ended September 30, 2008.

Pursuant to the written trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), adopted by the Company on March 20, 2008, the Company periodically repurchases shares of its Common Stock on the open market related to Employee Length of Service Awards and the stock portion of the Directors' annual retainer. The Company may suspend or terminate its Rule 10b5-1 trading plan at any time, so long as the suspension or termination is made in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 under the Exchange Act, or other applicable securities laws. There is no pool or maximum number of shares related to these purchases. Company repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
7/1/08 – 7/31/08	---	---	---	n/a
8/1/08 – 8/31/08		---	---	n/a
9/1/08 – 9/30/08	225	$26.60	225	n/a
Total	225	$26.60	225	n/a

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated October 24, 2008 Announcing Earnings For the Quarter Ended September 30, 2008.	Filed herewith
99.2	Maine Public Utilities Commission Order in Docket No. 2008-155	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: October 24, 2008 /s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: October 24, 2008 /s/ Laurence M. Brock
Laurence M. Brock
Chief Accounting Officer

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING

(Millions except common shares and per share data)

(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	**2008**	2007
Net Income	**$ 1.5**	$ 1.6	**$ 6.5**	$ 6.0
Less: Dividend Requirements on Preferred Stock	**---**	---	**0.1**	0.1
Net Income Applicable to Common Stock	**$ 1.5**	$ 1.6	**$ 6.4**	$ 5.9
Weighted Average Number of Common Shares Outstanding – Basic (000's)	**5,745**	5,659	**5,733**	5,643
Dilutive Effect of Stock Options and Restricted Stock (000's)	**3**	9	**5**	16
Weighted Average Number of Common Shares Outstanding – Diluted (000's)	**5,748**	5,668	**5,738**	5,659
Earnings Per Share – Basic	**$0.27**	$0.28	**$1.12**	$1.04
Earnings Per Share – Diluted	**$0.27**	$0.28	**$1.12**	$1.04

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2008

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2008

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2008

/s/ Laurence M. Brock

Laurence M. Brock
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Unitil Corporation (the "Company") on Form 10-Q for the period ending September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Chief Accounting Officer, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	October 24, 2008
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	October 24, 2008
/s/ Laurence M. Brock Laurence M. Brock	Chief Accounting Officer	October 24, 2008

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.20) Quarterly sales volumes for the previous 5 years, itemized for residential and other classifications of service.

Response:

Not applicable to Unitil Corporation.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.21) A description of the utility's projected need for external capital for the 2 year period immediately following the test year.

Response:

Unitil Corporation plans to continue to issue common stock through its Dividend Reinvestment Plan and other stock plans as filed with the Securities and Exchange Commission. At this time, Unitil Corporation does not have any plans in the next two years to do a long-term financing, including public common stock, preferred stock or long-term debt.

Unitil Corporation currently has an $80 million bank credit facility for its short-term debt requirements with $66.8 million outstanding as of December 31, 2010. Unitil Corporation utilizes and manages its short-term bank credit facility on a daily basis to meet the obligations of the Unitil Corporation Cash Pool. Unitil Corporation and its subsidiaries are individually and collectively members of the Cash Pool, which is the financing vehicle for day-to-day cash borrowing and investing. Unitil Corporation may increase or decrease the size of the bank credit facility in the next two years to manage the cash requirements of its subsidiaries.

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.22) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately subsequent to the test year;

Response:

Please see PUC 1604.01 (a) 25.22 - Attachment 1 - Confidential for projected sources and uses of funds for Unitil Corporation for the years 2011 and 2012.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
Sources and Uses of Funds for Years 2011 and 2012
Including the Projected Construction Budgets
($000)

See Volume 4 of 4 for Puc 1604.01(a) 25.22 - Attachment 1 CONFIDENTIAL

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.23) The provisions of any sinking funds associated with senior capital and a description of the rate at which any respective issues of senior capital will be retired, consistent with such sinking fund(s).

Response:

Please see the attached schedule of Unitil Corporation’s Sinking Fund Commitment, which is paid on 2022.
.

Unitil Corporation
Sinking Fund Commitments

	6.33% Due 5/1/2022 Bullet	UC Total
2010		-
2011		-
2012		-
2013		-
2014		-
2015		-
2016		-
2017		-
2018		-
2019		-
2020		-
2021		-
2022	20,000,000	20,000,000
2023		-
2024		-
2025		-
2026		-
2027		-
2028		-
2029		-
2030		-
2031		-
2032		-
2033		-
2034		-
2035		-
2036		-
2037		-
2038		-
2039		-
2040		-

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.24) If the short-term debt component of total invested capital is volatile, the amount outstanding, on a monthly basis, during the test year, for each short-term indebtedness.

Response:

Please refer to the attached schedule, showing Unitil Corporation's end of month balance and average daily balance of short-term debt outstanding for each month during the test year.

Unitil Corporation
Short-Term Debt Outstanding
12 Months Ended December 31, 2010

Line No.	Month	Month-End Amount Outstanding	Average Daily Borrowings
1	January 2010	$ 67,755,000	$ 65,642,581
2	February 2010	66,460,000	61,878,929
3	March 2010	19,250,000	23,471,613
4	April 2010	19,805,000	17,052,000
5	May 2010	17,460,000	17,890,968
6	June 2010	24,555,000	20,297,500
7	July 2010	30,185,000	27,390,645
8	August 2010	40,230,000	34,344,839
9	September 2010	46,335,000	43,958,500
10	October 2010	49,560,000	48,503,548
11	November 2010	57,770,000	54,164,000
12	December 2010	66,805,000	64,586,452

Northern Utilities, Inc.
DE 11-___

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(26) As to a subsidiary as referred to in (25) above, in lieu of duplicate copies of documentation required by Puc 1604.01(a)(5), (6), (11), (16), and (17), a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service;

(5) Detailed list of charitable contributions charged in the test year showing donee and the amount according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all contributions shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all contributions of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all contributions of $2,500 and more shall be reported;
d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all contributions of $5,000 and more shall be reported; and
e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution;

(6) List of advertising charged in the test year above the line showing expenditure by media and by subject matter according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all expenditures shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all expenditures of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all expenditures of $2,500 and more shall be reported; and

Northern Utilities, Inc.
DE 11-___

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all expenditures of $5,000 and more shall be reported;

(11) Detailed list of all membership fees, dues, donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all membership fees, dues and donations shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all membership fees, dues and donations of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all membership fees, dues and donations of $2,500 and more shall be reported; and
d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all membership fees, dues and donations of $5,000 and more shall be reported;

(16) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $100,000 in annual gross revenues, a list of all payments in excess of $1,000;
b. for utilities with annual gross revenues of $100,000 or between $100,000 and $10,000,000, a list of all payments in excess of $10,000;
c. For utilities with annual gross revenues of $10,000,000 or between $10,000,000 and $100,000,000, a list of all payments in excess of $50,000;
d. For utilities with annual gross revenues of $100,000,000 or in excess of $100,000,000, a list of all payments in excess of $100,000; and
e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular entity shall be on a cumulative basis,

Northern Utilities, Inc.
DE 11-___

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

indicating the number of items comprising the total amount of expenditure;

(17) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations;

Response:

Please see attached Certificate.

Northern Utilities, Inc.

Pursuant to the New Hampshire Code of Administrative Rules, Part 1604.01 (a)(26), Northern Utilities, Inc., hereby certifies the following:

With respect to the data required by Part 1604.01(a) (5), (6), (11), (16) and (17), no expense of the nature defined therein for the parent company (Unitil Corporation) is included in the cost of service for Northern Utilities, Inc., as filed in this case.

Laurence M. Brock

Laurence M. Brock
Controller and CAO,
Northern Utilities, Inc.

State of New Hampshire
County of Rockingham, ss.

Signed and sworn this

18th day of March, 2011

Robert A. LaBelle

Notary Public

ROBERT A. LaBELLE
Notary Public - New Hampshire
My Commission Expires April 28, 2015

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(27) For gas utilities, as defined in Puc 500, and for electric utilities, as defined in Puc 300, the uniform statistical report to the American Gas Association-Edison Electric Institute for the last 2 years; and

Response:

Northern Utilities, Inc. has not completed / provided any uniform statistical reports to the American Gas Association - Edison Electric Institute. However, Northern Utilities does file with the Pipeline Hazardous Materials Safety Administration ("PHMSA") the Form PHMSA F 7100.1-1 annual report that does provide statistical data on the Northern Utilities distribution system.

Please see the following reports:

- Attachment 1, Form PHMSA F 7100.1-1, 2009
- Attachment 2, Form PHMSA F 7100.1-1, 2008

NOTICE: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

Form Approved
OMB No. 2137-0522

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

ANNUAL REPORT FOR CALENDAR YEAR **2009**

GAS DISTRIBUTION SYSTEM

INITIAL REPORT **X**
SUPPLEMENTAL REPORT ☐

PART A - OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF OPERATOR
NORTHERN UTILITIES, INC.

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
325 West Rd
Number and Street
Portsmouth, Rockingham County
City and County1
New Hampshire, 03801
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER
/ 1 / 3 / 8 / 0 / 0 /

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
Number and Street
City and County
State and Zip Code

5. STATE IN WHICH SYSTEM OPERATES:/ N / H / (provide a **separate** report for each state in which system operates)

PART B - SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER	TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED								
	BARE	COATED	BARE	COATED							
MILES OF MAIN	32.63	0	0	82.10	358.06	11.33					484.83
NO. OF SERVICES	282			380	18806						19468

2. MILES OF MAINS IN SYSTEM AT END OF YEAR : **484.83**

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	TOTAL
STEEL	0.01	27.55	33.63	52.93	1.16	0	115.28
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON	0	0.40	6.07	4.63	0.23	0.	11.33
PLASTIC 1. PVC							
2. PE	0	183.20	94.69	79.97	0.20		358.06
3. ABS							
OTHER	0.02	0.05	0.01	0.07	0	0	0.16
OTHER							
SYSTEM TOTALS	0.03	211.20	134.40	137.61	1.59	0	484.83

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR : **19468** AVERAGE SERVICE LENGTH 70 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL		259	396		6	1	662
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON							
PLASTIC 1. PVC							
2. PE		14177	4474	144	11	0	18806
3. ABS							
OTHER							
OTHER							
SYSTEM TOTALS		14436	4870	144	17	1	19468

4. MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UN-KNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980–1989	1990–1999	2000–2009	TOTAL
MILES OF MAIN	45.66	11.20	1.50	3.68	19.70	30.06	79.83	200.04	92.47	484.83
NUMBER OF SERVICES	0	133	9	1526	22	861	3237	7417	6263	19468

PART C - TOTAL LEAKS ELIMINATED/REPAIRED DURING YEAR

CAUSE OF LEAK	Mains	Services
CORROSION	56	14
NATURAL FORCES	3	0
EXCAVATION	3	13
OTHER OUTSIDE FORCE DAMAGE	0	0
MATERIAL OR WELDS	4	3
EQUIPMENT	0	0
OPERATIONS	21	2
OTHER	4	5

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR **-0-**

PART D - TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

-0-

PART E - PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for the12 months ending June 30 of the reporting year.

[(Purchased gas + produced gas)
minus (customer use + company use + appropriate adjustments)]
divided by (purchased gas + produced gas) equals percent unaccounted for.

Input for year ending 6/30 -2.76 **%.**

PART F - ADDITIONAL INFORMATION

PART G - PREPARER AND AUTHORIZED SIGNATURE

Simone T. Major, Senior Gas Operations Associate
(type or print) Preparer's Name and Title

603-294-5160
Area Code and Telephone Number

major@unitil.com
Preparer's email address

603-430-5473
Area Code and Facsimile Number

Mel Ciulla, Mgr. Gas Distribution Operations
Name and Title of Person Signing

603-294-5148
Area Code and Telephone Number

Authorized Signature

Date

Form Approved
OMB No. 2137-0522

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

ANNUAL REPORT FOR CALENDAR YEAR **2008**
GAS DISTRIBUTION SYSTEM

INITIAL REPORT **X**
SUPPLEMENTAL REPORT ☐

PART A - OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF OPERATOR
   NORTHERN UTILITIES, INC.
2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
   325 West Rd
   Number and Street
   Portsmouth, Rockingham County
   City and County1
   New Hampshire, 03801
   State and Zip Code
3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER
   / 1 / 3 / 8 / 0 / 0 /
4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
   Number and Street
   City and County
   State and Zip Code
5. STATE IN WHICH SYSTEM OPERATES:/ **N / H** / (provide a **separate** report for each state in which system operates)

PART B - SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER	TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED								
	BARE	COATED	BARE	COATED							
MILES OF MAIN	39.27	.1	0	80.80	339.39	10.71					470.27
NO. OF SERVICES	374	13	0	353	18548						19288

2. MILES OF MAINS IN SYSTEM AT END OF YEAR **470.27**

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	TOTAL
STEEL		28.46	34.90	55.94	0.87		120.17
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON		0.08	5.30	5.04	0.29		10.71
PLASTIC 1. PVC							
2. PE		175.06	87.08	77.25			339.39
3. ABS							
OTHER							
OTHER							
SYSTEM TOTALS		203.60	127.28	138.23	1.16		470.27

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR **19288** AVERAGE SERVICE LENGTH **70** FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL		291	442		6	1	740
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON							
PLASTIC 1. PVC							
2. PE		14016	4379	142	11	0	18548
3. ABS							
OTHER							
OTHER							
SYSTEM TOTALS		14307	4821	142	17	1	19288

4. MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UN-KNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980–1989	1990–1999	2000–2009	TOTAL
MILES OF MAIN		8	20	15	59	41	100	143	84	470
NUMBER OF SERVICES		501	363	1508	1828	1470	3287	5048	5283	19288

PART C - TOTAL LEAKS ELIMINATED/REPAIRED DURING YEAR

CAUSE OF LEAK	Mains	Services
CORROSION	55	26
NATURAL FORCES	1	0
EXCAVATION	5	16
OTHER OUTSIDE FORCE DAMAGE	0	1
MATERIAL OR WELDS	1	3
EQUIPMENT	1	0
OPERATIONS	18	3
OTHER	9	3

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR **-0-**

PART D - TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

-0-

PART E - PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for the12 months ending June 30 of the reporting year.

[(Purchased gas + produced gas)
minus (customer use + company use + appropriate adjustments)]
divided by (purchased gas + produced gas) equals percent unaccounted for.

Input for year ending 6/30 **0.57** %.

PART F - ADDITIONAL INFORMATION

PART G - PREPARER AND AUTHORIZED SIGNATURE

Simone T. Major
(type or print) Preparer's Name and Title

603-294-5160
Area Code and Telephone Number

major@unitil.com
Preparer's email address

603-430-5473
Area Code and Facsimile Number

Name and Title of Person Signing

Area Code and Telephone Number

Authorized Signature

Northern Utilities, Inc.
DE 11-069

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(28) Support figures appearing on written testimony and/or in accompanying exhibits.

Response:

Please refer to the schedules and workpapers accompanying the testimony presented in this filing.