FINANCIAL STATEMENTS
AND
INDEPENDENT AUDITORS' REPORT

NORTHERN UTILITIES, INC.
For the Period Ended December 31, 2016

NORTHERN UTILITIES, INC.

CERTIFICATION TO NOTEHOLDERS

I hereby certify that the accompanying Balance Sheets as of December 31, 2016 and December 31, 2015, Statements of Earnings for the years ended December 31, 2016, 2015 and 2014, Statements of Cash Flows for the years ended December 31, 2016, 2015 and 2014 and Statements of Changes in Shareholder's Equity for the years ended December 31, 2016, 2015 and 2014 were, to the best of my knowledge and belief, properly prepared and are correct.

I additionally certify that the accompanying calculation worksheet, pursuant to Sections 10.1 and 10.5 of the Note Purchase Agreements dated December 3, 2008, March 2, 2010 and October 15, 2014, was, to the best of my knowledge and belief, properly prepared and is correct.

I further certify that I have reviewed the provisions of the Note Purchase Agreements dated December 3, 2008, March 2, 2010 and October 15, 2014, and to the best of my knowledge and belief the Company was, and remains in compliance with the provisions of this Agreement and no Default or Event of Default exists or occurred during the period of the financial statements ending December 31, 2016 and up to the date of this certification.

Laurence M. Brock
Controller

David Chong
Treasurer

March 17, 2017

Northern Utilities, Inc.

(a) Ratio of Funded Indebtedness to Total Capitalization

The information below is being provided in accordance with Section 10.1 (a) "Calculation Worksheets" of the Note Purchase Agreements for Northern Utilities, Inc.'s 6.95% Senior Notes, due December 3, 2018, 7.72% Senior Notes, due December 3, 2038, 5.29% Senior Notes, due March 2, 2020 and 4.42% Senior Notes, due October 14, 2044.

		(Millions) As of December 31, 2016
Funded Indebtedness [1]	$	134.2
Total Capitalization	$	289.4
Funded Indebtedness / Total Capitalization		46.4%

[1] Funded Indebtedness is Total Capitalization less Common Stock Equity as of the balance sheet date.

Northern Utilities, Inc.

(a) Restrictions on Dividends

The information below is being provided in accordance with Section 10.5 (a) "Calculation Worksheets" of the Note Purchase Agreements for Northern Utilities, Inc.'s 6.95% Senior Notes, due December 3, 2018, 7.72% Senior Notes, due December 3, 2038, 5.29% Senior Notes, due March 2, 2020 and 4.42% Senior Notes, due October 14, 2044.

		(Millions) As of December 31, 2016
Stated Amount	$	9.0
Add: Equity Contributions - 2010 - 2012		47.5
Add: Net Income - 2008 -2015		48.6
Add: Net Income - 2016		10.8
Subtotal	**$**	**115.9**
Less: Dividends Declared / Paid - 2008 - 2015		38.2
Less: Dividends Declared / Paid - 2016		9.2
Available for Dividends	**$**	**68.5**

Deloitte.

Deloitte & Touche LLP
200 Berkeley Street
Boston, MA 02116-5022
USA

Tel: + 1 617 437 2000
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Northern Utilities, Inc.
Hampton, NH

We have audited the accompanying financial statements of Northern Utilities, Inc. (the "Company") (a wholly-owned subsidiary of Unitil Corporation), which comprise the balance sheets as of December 31, 2016 and 2015, and the related statements of earnings, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2016, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northern Utilities, Inc. as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended

December 31, 2016, in accordance with accounting principles generally accepted in the United States of America.

Other Matter

The accompanying financial statements have been prepared from the separate records maintained by Unitil Corporation and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated company. Portions of certain income and expenses represent allocations made from the Company's parent applicable to the Company's parent as a whole.

Deloitte & Touche LLP

Boston, MA
March 17, 2017

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
($ in Millions)

	Year Ended December 31,		
	2016	2015	2014
Operating Revenues	**$ 150.1**	$ 169.9	$ 164.1
Operating Expenses:			
Cost of Gas Sales	**73.7**	93.7	91.4
Operation and Maintenance	**26.7**	27.1	24.1
Depreciation and Amortization	**14.6**	13.7	12.5
Taxes Other Than Income Taxes	**7.3**	6.4	6.1
Total Operating Expenses	**122.3**	140.9	134.1
Operating Income	**27.8**	29.0	30.0
Interest Expense	**10.2**	10.1	8.5
Other (Income) Expense, net	**(0.1)**	(1.6)	(0.1)
Income Before Income Taxes	**17.7**	20.5	21.6
Income Taxes	**6.9**	8.3	8.8
Net Income	**$ 10.8**	$ 12.2	$ 12.8

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
BALANCE SHEETS
($ in Millions)

	December 31, 2016	December 31, 2015
ASSETS:		
Current Assets:		
Cash and Cash Equivalents	$ 0.5	$ 0.7
Accounts Receivable – (Net of Allowance for Doubtful Accounts of $0.2 and $0.4)	20.2	15.2
Accrued Revenue	15.0	9.0
Exchange Gas Receivable	7.8	10.3
Gas Inventory	0.4	0.5
Materials and Supplies	4.6	4.1
Prepayments and Other	2.2	1.7
Total Current Assets	50.7	41.5
Utility Plant:		
Gas	451.1	409.1
Construction Work in Progress	18.6	19.3
Utility Plant	469.7	428.4
Less: Accumulated Depreciation	85.5	78.8
Net Utility Plant	384.2	349.6
Other Noncurrent Assets:		
Regulatory Assets	23.2	19.6
Other Assets	4.1	5.3
Total Other Noncurrent Assets	27.3	24.9
TOTAL ASSETS	$ 462.2	$ 416.0

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
BALANCE SHEETS
($ in Millions, except par value and shares data)

	December 31, 2016	2015
LIABILITIES AND CAPITALIZATION:		
Current Liabilities:		
Accounts Payable	$ **13.4**	$ 13.1
Short-Term Debt	**37.0**	17.8
Long-Term Debt, Current Portion	**9.9**	10.0
Due to Affiliates	**0.2**	1.3
Energy Supply Contract Obligations	**7.8**	10.3
Dividends Payable	**1.9**	2.9
Environmental Obligations	**0.3**	1.1
Regulatory Liabilities	**4.7**	8.3
Other Current Liabilities	**3.9**	5.2
Total Current Liabilities	**79.1**	70.0
Noncurrent Liabilities:		
Deferred Income Taxes	**28.0**	17.4
Cost of Removal Obligations	**28.7**	26.9
Retirement Benefit Obligations	**32.8**	25.2
Regulatory Liabilities	**2.6**	8.1
Environmental Obligations	**1.5**	0.5
Other Noncurrent Liabilities	**0.1**	0.3
Total Noncurrent Liabilities	**93.7**	78.4
Capitalization:		
Long-term Debt, Less Current Portion	**134.2**	144.0
Shareholder's Equity:		
Common Stock, $10 Par Value		
Authorized - 200 shares		
Issued and Outstanding - 100 shares	**143.2**	113.2
Retained Earnings	**12.0**	10.4
Total Shareholder's Equity	**155.2**	123.6
Total Capitalization	**289.4**	267.6
Commitments and Contingencies (Note 5)		
TOTAL LIABILITIES AND CAPITALIZATION	$ **462.2**	$ 416.0

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF CASH FLOWS
($ in Millions)

	Year Ended December 31,		
	2016	2015	2014
Operating Activities:			
Net Income	$ **10.8**	$ 12.2	$ 12.8
Adjustments to Reconcile Net Income to Cash Provided by (Used in) Operating Activities:			
Depreciation and Amortization	**14.6**	13.7	12.5
Deferred Tax Provision	**13.2**	6.0	10.0
Changes in Working Capital Items:			
Accounts Receivable	**(5.0)**	8.1	(3.0)
Accrued Revenue	**(6.0)**	6.1	0.6
Exchange Gas Receivable	**2.5**	3.9	(4.4)
Due to/from Affiliates	**(1.1)**	(0.9)	2.9
Accounts Payable	**0.3**	(3.8)	1.0
Regulatory Liabilities	**(3.6)**	7.8	(0.4)
Other Changes in Working Capital Items	**(3.0)**	1.8	(0.1)
Deferred Regulatory and Other Charges	**(3.4)**	7.0	1.7
Other, net	**(1.8)**	(2.2)	(1.6)
Cash Provided by Operating Activities	**17.5**	59.7	32.0
Investing Activities:			
Property, Plant, and Equipment Additions	**(44.2)**	(50.0)	(48.7)
Cash Used in Investing Activities	**(44.2)**	(50.0)	(48.7)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt, net	**19.2**	5.1	(30.3)
Issuance of Long-Term Debt	---	---	50.0
Repayment of Long-Term Debt	**(10.0)**	---	---
Net (Decrease) Increase in Exchange Gas Financing	**(2.5)**	(3.9)	4.4
Dividends Paid	**(10.2)**	(10.9)	(7.2)
Equity Contribution	**30.0**	---	---
Cash (Used in) Provided by Financing Activities	**26.5**	(9.7)	16.9
Net Increase (Decrease) in Cash and Cash Equivalents	**(0.2)**	---	0.2
Cash and Cash Equivalents at Beginning of Year	**0.7**	0.7	0.5
Cash and Cash Equivalents at End of Year	$ **0.5**	$ 0.7	$ 0.7
Supplemental Cash Flow Information:			
Interest Paid	$ **9.9**	$ 9.5	$ 7.8
Income Taxes (Refunded) Paid	$ **5.2**	$ 1.0	$ 2.8
Non-cash Investing Activity:			
Capital Expenditures Included in Accounts Payable	$ **0.1**	$ 0.2	$ 0.1

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
($ in Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2014	$ 113.2	$ 6.2	**$ 119.4**
Net Income		12.8	**12.8**
Dividends Declared		(9.9)	**(9.9)**
Balance at December 31, 2014	$ 113.2	$ 9.1	**$ 122.3**
Net Income		12.2	**12.2**
Dividends Declared		(10.9)	**(10.9)**
Balance at December 31, 2015	$ 113.2	$ 10.4	**$ 123.6**
Net Income		10.8	**10.8**
Dividends Declared		(9.2)	**(9.2)**
Equity Contribution	30.0		**30.0**
Balance at December 31, 2016	$ 143.2	$ 12.0	**$ 155.2**

(The accompanying Notes are an integral part of these financial statements.)

NOTE 1: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations – Northern Utilities, Inc. (Northern Utilities or Company), a wholly-owned subsidiary of Unitil Corporation (Unitil), 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 and is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Maine Public Utilities Commission (MPUC). Northern Utilities' accounting policies conform with Generally Accepted Accounting Principles in the United States of America (U.S. GAAP), as applied in the case of regulated public utilities, and are in accordance with the accounting requirements of the NHPUC, MPUC and the Federal Energy Regulatory Commission (FERC). A description of Northern Utilities' significant accounting policies follows.

Transactions with Affiliates - In addition to its investment in Northern Utilities, Unitil has interests in two other distribution utility companies, one doing business in New Hampshire and one doing business in Massachusetts, an interstate natural gas transmission pipeline company (Granite State), a service company (Unitil Service Corp.), a realty company, a power company, and a non-regulated energy consulting company.

Transactions among Northern Utilities and other affiliated companies include professional and management services rendered by Unitil Service Corp. of approximately $20.1 million, $19.1 million and $16.6 million in the years ended December 31, 2016, 2015 and 2014, respectively. The Company's transactions with affiliated companies are subject to review by the NHPUC, MPUC, the Securities and Exchange Commission (SEC) and the FERC.

In 2016, Northern Utilities received a capital contribution of $30.0 million from Unitil.

Approximately 7%, 5% and 5% of the Company's natural gas purchases for the years ended December 31, 2016, 2015 and 2014, respectively, were from Granite State.

Use of Estimates - The preparation of 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 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.

Fair Value – The Financial Accounting Standards Board (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.

There have been no changes in the valuation techniques used during the current period.

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 natural 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.

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 financial statements. Provisions for depreciation were equivalent to an annual composite rate of 3.13%, 3.15% and 3.14% in 2016, 2015 and 2014, respectively, based on the average depreciable property balances at the beginning and end of the year. Depreciation expense for Northern Utilities was $14.0 million, $12.7 million and $11.7 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Sales Taxes – The Company bills its customers sales tax in Maine. This tax is remitted to the Maine Revenue Service and is excluded from revenues on the Company's 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 Balance Sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes. The Company classifies penalty and interest expense related to income tax liabilities as income tax expense and interest expense, respectively, in the Statements of Earnings.

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 deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. In accordance with the FASB Codification, the Company periodically 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.

In the first quarter of 2016, the Company adopted ASU 2015-17 which simplifies the presentation of deferred income taxes in a classified statement of financial position. Current generally accepted accounting principles (GAAP) require an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. ASU 2015-17 amends current GAAP to require that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position.

For all periods presented in the Company's Financial Statements for the year ended December 31, 2016, deferred income taxes are reported as "Deferred Income Taxes" in the "Noncurrent Liabilities" section on the Balance Sheets. Prior to adoption, the Company reported deferred income taxes in either the "Current Assets" or "Current Liabilities" and "Other Noncurrent Assets" or "Noncurrent Liabilities" sections on the Balance Sheets, depending on whether the net current deferred income taxes and net noncurrent deferred income taxes were in an asset or liability position, respectively. The change in presentation for the year ended December 31, 2016 resulted in a reduction of both "Current Assets" and "Noncurrent Liabilities" for all prior periods presented.

Unitil Corporation and its subsidiaries, including Northern Utilities, file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal and state income taxes paid by Unitil Corporation are collected from, or refunded to, Unitil Corporation's subsidiaries based on a tax sharing agreement between Unitil Corporation and each of its affiliated subsidiaries. The tax sharing agreement apportions taxes paid among Unitil Corporation and its subsidiaries as though each affiliate had filed a separate tax return.

Cash and Cash Equivalents – Cash and Cash Equivalents 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 has cash deposits to satisfy requirements for its operational balancing agreement. There was $75 thousand and $50 thousand deposited for this purpose on December 31, 2016 and 2015, respectively. These amounts are included in Cash and Cash Equivalents on the Company's Balance Sheets.

Allowance for Uncollectible 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 natural 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 takes into account the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by regulators to recover a portion of the costs of its 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. 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.

Accrued Revenue - Accrued Revenue includes the current portion of Regulatory Assets (see "Regulatory Accounting" below and unbilled revenues (see Utility Revenue Recognition above.) The following table shows the components of Accrued Revenue as of December 31, 2016 and 2015.

	December 31,	
Accrued Revenue ($ millions)	**2016**	2015
Regulatory Assets – Current	**$ 9.1**	$ 3.2
Unbilled Revenues	**5.9**	5.8
Total Accrued Revenue	**$ 15.0**	$ 9.0

Exchange Gas Receivable – The Company has a gas exchange and storage agreement whereby natural gas purchases during the months of April through October are delivered to a third party. The third party delivers natural gas back to the Company during the months of November through March. The exchange and storage gas volumes are recorded at weighted average cost. Exchange Gas Receivable was $7.8 million and $10.3 million at December 31, 2016 and 2015, respectively. Although the asset management agreement associated with the exchange gas receivable may qualify as an embedded derivative because its terms contain notional amounts, the Company does not classify the agreement as a derivative because it meets the criteria for exception as a contract for normal purchases and normal sales, as such instruments are defined per the FASB Codification.

Gas Inventory – The Company uses the weighted average cost methodology to value natural gas inventory. Natural gas inventory was $0.5 million and $0.5 million at December 31, 2016 and 2015, respectively.

	December 31,	
Gas Inventory ($ millions)	**2016**	2015
Natural Gas	**$ 0.3**	$ 0.4
Liquefied Natural Gas	**0.1**	0.1
Total Gas Inventory	**$ 0.4**	**$** 0.5

Materials and Supplies – Materials and Supplies consist of distribution construction and repair materials. Materials and Supplies are stated at average cost and are issued from stock using the average cost of existing stock. Materials and Supplies are recorded when purchased and subsequently charged to expense or capitalized to property, plant, and equipment when installed. Materials and Supplies were $4.6 million and $4.1 million at December 31, 2016 and 2015, respectively.

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 annualized interest rate applied to AFUDC was 1.56%, 3.24% and 1.56% in 2016, 2015 and 2014, respectively. The costs of current repairs and minor replacements are charged to 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, 2016 and 2015, the Company estimates that the cost of removal amounts, which are recorded on the Company's Balance Sheets in Cost of Removal Obligations are $28.7 million and $26.9 million, respectively.

Goodwill and Intangible Assets – On December 1, 2008, the Company and Granite State were acquired by Unitil, (the "Acquisitions"), and the Company recognized an estimated bargain purchase adjustment, the Plant Acquisition Adjustment (PAA), as a reduction to Utility Plant, to be amortized over a ten year period. For the years ended December 31, 2016, 2015 and 2014, the Company recognized credits to amortization expense totaling $2.2 million, $2.2 million and $2.2 million, respectively. The Company's unamortized PAA balance at December 31, 2016 and 2015 was $4.2 million and $6.5 million, respectively, and is included in Net Utility Plant on the Company's Balance Sheets. This balance will be amortized over the next two years.

Regulatory Accounting – Northern Utilities' principal business is the distribution of natural gas and it is regulated by the MPUC and NHPUC. 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.

	December 31,	
Regulatory Assets consist of the following ($ millions)	**2016**	2015
Retirement Benefit Obligations	**$ 14.1**	$ 10.4
Regulatory Tracker Mechanisms	**8.2**	2.9
Environmental Obligations	**7.4**	6.1
Income Taxes	**1.6**	1.9
Other	**1.0**	1.5
Total Regulatory Assets	**$ 32.3**	$ 22.8
Less: Current Portion of Regulatory Assets [1]	**9.1**	3.2
Regulatory Assets - noncurrent	**$ 23.2**	$ 19.6

(1) Reflects amounts included in Accrued Revenue on the Company's Balance Sheets.

	December 31,	
Regulatory Liabilities consist of the following ($ millions)	**2016**	**2015**
Regulatory Tracker Mechanisms	$ **0.5**	$ 0.7
Gas Pipeline Refund (Note 5)	**6.8**	**15.7**
Total Regulatory Liabilities	**7.3**	16.4
Less: Current Portion of Regulatory Liabilities	**4.7**	8.3
Regulatory Liabilities - noncurrent	**$ 2.6**	$ 8.1

Generally, the Company receives a return on investment on its Regulatory Assets for which a cash outflow has been made. Included in Regulatory Assets as of December 31, 2016 are $6.0 million of environmental costs, rate case costs and other expenditures to be recovered over the next seven years. Regulators have authorized recovery of these expenditures, but without a return. The Company expects that it will recover all its investments in long-lived assets through its utility rates, including those amounts recognized as 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.

Derivatives – The Company's regulated energy subsidiaries enter into energy supply contracts to serve their electric and gas customers. The Company follows a procedure for determining whether each contract qualifies as a derivative instrument under the guidance provided by the FASB Codification on Derivatives and Hedging. For each contract, the Company reviews and documents the key terms of the contract. Based on those terms and any additional relevant components of the contract, the Company determines and documents whether the contract qualifies as a derivative instrument as defined in the FASB Codification. The Company has determined that none of its energy supply contracts, other than the regulatory approved hedging program, described below, qualifies as a derivative instrument under the guidance set forth in the FASB Codification.

The Company has a regulatory approved hedging program for Northern Utilities designed to fix or cap a portion of its gas supply costs for the coming years of service. Prior to April 2013 Northern Utilities purchased natural gas futures contracts on the New York Mercantile Exchange (NYMEX) that correspond to associated delivery months. Beginning in April 2013, the hedging program was redesigned and the Company began purchasing call option contracts on NYMEX natural gas futures contracts for future winter period months. As of December 31, 2015, all futures contracts purchased under the prior program design have been sold and the hedging portfolio now consists entirely of call option contracts.

Any gains or losses resulting from the change in the fair value of these derivatives are passed through to customers directly through Northern Utilities' Cost of Gas Adjustment Clause. The fair value of these derivatives is determined using Level 2 inputs (valuations based on quoted prices in markets that are not active or for which all significant inputs are observable, either directly or indirectly), 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 Cost of Gas Sales when the gains and losses are passed through to customers through the Cost of Gas Adjustment Clause.

As of December 31, 2016 and December 31, 2015, the Company had 2.0 billion and 2.5 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. The tables below include disclosure of the derivative assets and liabilities and the recognition of the charges from their corresponding regulatory liabilities and assets, respectively into Cost of Gas Sales. The current and noncurrent portions of these regulatory assets are recorded as Accrued Revenue and Regulatory Assets, respectively, on the Company's Balance Sheets. The current and noncurrent portions of these regulatory liabilities are recorded as Regulatory Liabilities and Other Noncurrent Liabilities, respectively on the Company's Balance Sheets.

Fair Value Amount of Derivative Assets / Liabilities (millions) Offset in Regulatory Liabilities / Assets, as of:

Description	Balance Sheet Location	Fair Value December 31, 2016	Fair Value December 31, 2015
Derivative Assets			
Natural Gas Futures / Options Contracts	Prepayments and Other	$ 0.1	$ ---
Natural Gas Futures / Options Contracts	Other Noncurrent Assets	0.3	---
Total Derivative Assets		$ 0.4	$ ---
Derivative Liabilities			
Natural Gas Futures / Options Contracts	Other Current Liabilities	$ ---	$ ---
Natural Gas Futures / Options Contracts	Other Noncurrent Liabilities	---	---
Total Derivative Liabilities		$ ---	$ ---

	Twelve Months Ended December 31, 2016	Twelve Months Ended December 31, 2015
Amount of Loss / (Gain) Recognized in Regulatory Assets (Liabilities) for Derivatives:		
Natural Gas Futures / Options Contracts	$ (0.1)	$ 0.3
Amount of Loss / (Gain) Reclassified into the Consolidated Statements of Earnings[1]:		
Cost of Gas Sales	$ 0.3	$ 0.2

(1) These amounts are offset in the Statements of Earnings with Accrued Revenue and therefore there is no effect on earnings.

Energy Supply Obligations— The Company enters into asset management agreements under which it 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. The gas volumes related to these agreements are recorded in Exchange Gas Receivable on the Company's Balance Sheets while the corresponding obligations are recorded in Energy Supply Obligations.

Retirement Benefit Obligations – The Company co-sponsors the Unitil Corporation Retirement Plan (Pension Plan), which is a defined benefit pension plan covering substantially all of its employees. The Company also co-sponsors a non-qualified 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 co-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 a liability for the underfunded status of its 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 gas rates. See Note 7.

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, 2016, 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 Financial Statements below. 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. 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, 2016, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 5, Commitments and Contingencies below. 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.

Off-Balance Sheet Arrangements – As of December 31, 2016, 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 and other equipment and motor vehicles under operating leases and, in the Company's opinion, the amount of these transactions is not material.

Concentrations of Credit Risk – 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. Accounts receivable may be affected by changes in economic conditions. However, the Company believes that the credit risk associated with accounts receivable is offset by the diversification of the Company's customer base. The Company believes it is not exposed to any significant credit risk on cash and cash equivalents and accounts receivable.

Recently Issued Pronouncements - In April and March 2016, the FASB issued ASU 2016-10 and ASU 2016-08, respectively. ASU 2016-10 clarifies the implementation guidance on licensing and the identification of performance obligations considerations included in ASU 2014-09. ASU 2016-08 provides amendments to clarify the implementation guidance on principal versus agent considerations included in ASU 2014-09. In August 2015, the FASB issued ASU 2015-14, which defers the effective date of ASU 2014-09. ASU 2014-09 outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The effective date of this pronouncement is for fiscal years beginning after December 15, 2017 with early adoption permitted as of the original effective date. The Company will implement the standard in the first quarter of 2018 on a modified retrospective basis and it is not expected to have a material impact on the Company's Financial Statements.

In March 2016, the FASB issued ASU 2016-09, which provides for improvements to employee share-based payment accounting. ASU 2016-09 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. ASU 2016-09 simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The Company does not expect that this new guidance will have a material impact on the Company's Financial Statements.

In February 2016, the FASB issued ASU 2016-02, which replaces the existing guidance in Accounting Standard Codification 840, Leases. ASU 2016-02 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. ASU 2016-02 requires a dual approach for lessee accounting under which a lessee would account for leases as finance (also referred to as capital) leases or operating leases. Both finance leases and operating leases will result in the lessee recognizing a right-of-use asset and corresponding lease liability. For finance leases the lessee would recognize interest expense and amortization of the right-of-use asset and for operating leases the lessee would recognize straight-line total lease expense. The Company is evaluating the impact that this new guidance will have on the Company's Financial Statements.

In January 2016, the FASB issued Accounting Standards Update (ASU) 2016-01 which addresses certain aspects of recognition, measurement, presentation and disclosure of financial instruments. A financial instrument is defined as cash, evidence of ownership interest in a company or other entity, or a contract that both: (i) imposes on one entity a contractual obligation either to deliver cash or another financial instrument to a second entity or to exchange other financial instruments on potentially unfavorable terms with the second entity and (ii) conveys to that second entity a contractual right either to receive cash or another financial instruments from the first entity or to exchange other financial instruments on potentially favorable terms with the first entity. This pronouncement is effective for financial statements issued for annual periods beginning after December 15, 2017 and interim periods within those annual periods with earlier application permitted as of the beginning of the fiscal year of adoption. The Company is evaluating the impact that this new guidance will have on the Company's Financial Statements.

In May 2015, the FASB issued ASU 2015-07 which provides authoritative guidance removing the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. Investments measured at net asset value per share using the practical expedient will be presented as a reconciling item between the fair value hierarchy disclosure and the investment line item on the statement of financial position. The guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Rather, those disclosures are limited to investments for which the entity has elected to measure the fair value using the practical expedient. The guidance is effective for fiscal years beginning after December 15, 2015 with early adoption permitted. The guidance is required to be applied retrospectively to all periods presented. The Company adopted this new guidance and it did not have a material impact on the Company's Financial Statements.

Other than the pronouncements discussed above, there are no recently issued pronouncements that the Company has not already adopted or that have a material impact on the Company.

Subsequent Events – The Company has evaluated all events or transactions through March 17, 2017, the date the Financial Statements were available to be issued. During this period, the Company did not have any material subsequent events that would result in adjustment to or disclosure in its Financial Statements.

NOTE 2: DEBT AND FINANCING ARRANGEMENTS

Long-Term Debt and Interest Expense

All the Company's long-term debt is issued under unsecured promissory notes with negative pledge provisions, which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for the Company to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that the Company have total funded indebtedness less than 65% of total capitalization. The Company's unsecured promissory note agreements require that if it defaults on any long-term debt agreement, it would constitute a default under all its long-term debt agreements. The default provisions are not triggered by the actions or defaults of other companies owned by Unitil. The Company's long-term debt agreements also contain covenants restricting its ability to incur liens and to enter into sale and leaseback transactions, and restricting its ability to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

On October 15, 2014, Northern Utilities completed a private placement of $50 million aggregate principal amount of 4.42% Senior Unsecured Notes due October 15, 2044 to institutional investors. The proceeds from the offering were used to repay short-term debt and for general corporate purposes.

Details of long-term debt at December 31, 2016 and 2015 are shown below:

Long-term Debt ($ millions)	December 31, 2016	December 31, 2015
Senior Notes:		
6.95% Senior Notes, Series A, Due December 3, 2018	**$ 20.0**	$ 30.0
5.29% Senior Notes, Due March 2, 2020	**25.0**	25.0
7.72% Senior Notes, Series B, Due December 3, 2038	**50.0**	50.0
4.42% Senior Notes, Due October 15, 2044	**50.0**	50.0
Total Long-Term Debt	**145.0**	155.0
Less: Unamortized Debt Issuance Costs	**0.9**	1.0
Total Long-Term Debt, net of Unamortized Debt Issuance Costs	**144.1**	154.0
Less: Current Portion	**9.9**	10.0
Total Long-Term Debt, Less Current Portion	**$ 134.2**	$ 144.0

The aggregate amount of Note repayment requirements is $10.0 million in 2017, $18.4 million in 2018, $8.4 million in 2019, $8.2 million in 2020, $0 in 2021 and $100.0 million thereafter.

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, 2016 is estimated to be approximately $160.1 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. 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. The fair value of the Company's long-term debt is estimated 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.) 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. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

Credit Arrangements

Northern Utilities' short-term borrowings are presently provided under a cash pooling and loan agreement between Unitil and its subsidiaries. Under the existing pooling and loan agreement, Unitil Corporation borrows, as required, from its banks on behalf of its subsidiaries. At December 31, 2016, Unitil had unsecured committed bank lines of credit for short-term debt aggregating $120 million. The weighted average interest rates on all short-term borrowings were 1.8%, 1.5% and 1.6% during 2016, 2015 and 2014, respectively. The Company had short-term debt outstanding through bank borrowings of approximately $37.0 million and $17.8 million at December 31, 2016 and 2015, 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 $9.9 million and $10.8 million of natural gas storage inventory at December 31, 2016 and 2015, respectively, related to these asset management agreements. The amount of natural gas inventory released in December 2016, which was payable in January 2017, was $2.1 million and recorded in Accounts Payable at December 31, 2016. The amount of natural gas inventory released in December 2015, which was payable in January 2016, was $0.6 million and recorded in Accounts Payable at December 31, 2015.

Leases

The Company leases some of its vehicles under operating lease arrangements. The following is a schedule of future operating lease payment obligations as of December 31, 2016:

Year Ending December 31, ($000's)		
2017	$	499
2018		388
2019		253
2020		152
2021		22
2022 - 2026		---
Total Future Operating Lease Payments	$	1,314

Total rental expense charged to operations for the years ended December 31, 2016, 2015 and 2014 amounted to $672,000, $603,000 and $467,000, respectively.

NOTE 3: RESTRICTION ON DIVIDENDS

Under the terms of the Note Purchase Agreements relating to Northern Utilities' Senior Notes, $98.4 million was available for dividends and similar distributions at December 31, 2016. Common dividends declared by Northern Utilities are paid exclusively to Unitil Corporation.

NOTE 4: ENERGY SUPPLY

Natural Gas Supply:

Northern Utilities' Commercial and Industrial (C&I) natural gas customers are entitled to purchase their natural gas supply from third-party gas suppliers. Many of Northern Utilities' largest and some medium C&I customers purchase their gas supply from third party suppliers, while most small C&I customers, as well as all residential customers, purchase their gas supply from Northern Utilities under regulated rates and tariffs. As of December 2016, 78% of Northern Utilities' largest New Hampshire gas customers, representing 27% of the Company's New Hampshire gas sales and 66% of Northern Utilities' largest Maine customers, representing 26% of the Company's Maine gas sales, are purchasing gas supply from a third-party supplier. 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 Cost of Gas Sales in the Statements of Earnings.

Regulated Natural Gas Supply:

The Company 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 liquefied natural gas (LNG), to truck supplies to each storage facility within Northern Utilities' service territory.

Northern Utilities has available under firm contract 115,000 million British Thermal Units per day of year-round and seasonal transportation capacity to its distribution facilities, and 3.6 billion cubic feet of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns a LNG natural gas storage and vaporization facility. This plant is used principally during peak load periods to augment the supply of pipeline natural gas.

NOTE 5: COMMITMENTS AND CONTINGENCIES

Regulatory Matters

Overview - 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 approximately 64,100 customers in 44 New Hampshire and southern Maine communities at rates established under traditional cost of service regulation. Under this regulatory structure, the Company recovers the cost of providing distribution service to its customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. The Company's business customers are entitled to purchase their natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through the Company as the provider of basic service energy supply. The Company purchases natural gas for basic service from unaffiliated wholesale suppliers and recovers the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

Base Rates - Maine - The rate case settlement in Northern Utilities' Maine division's last rate case allowed the Company to implement a Targeted Infrastructure Replacement Adjustment (TIRA) rate mechanism to adjust base distribution rates annually to recover the revenue requirements associated with targeted investments in gas distribution system infrastructure replacement and upgrade projects. The TIRA has an initial term of four years and covers targeted capital expenditures in 2013 through 2016. The 2016 TIRA, for 2015 expenditures, provides for an annual increase in distribution base revenue of $1.5 million, effective May 1, 2016, and was approved by the MPUC on April 28, 2016. The 2017 TIRA, for 2016 expenditures, which is pending approval by the MPUC, requests an annual increase in distribution base revenue of $1.1 million, effective May 1, 2017.

Targeted Area Build-out Program - Maine - On December 22, 2015 the MPUC approved a new Targeted Area Build-out program and associated rate surcharge mechanism. This program is designed to allow the economic extension of natural gas mains to new, targeted service areas in Maine. It allows customers in the targeted area the ability to pay a monthly rate surcharge, instead of a large upfront payment or capital contribution to connect to the natural gas delivery system. The first targeted area of the program, which was approved by the MPUC and begun in 2016, is a three year effort in the City of Saco with the potential to add 1,000 new customers and approximately $1 million in annual distribution revenue in the Saco area. The second target, which is pending approval by the MPUC, will be in the City of Sanford and has the potential to add over 2,000 customers and over $2 million in distribution revenue. The Company will continue to evaluate the success of the program and ways to economically reach new targeted service areas.

Base Rates - New Hampshire - Northern Utilities' New Hampshire division's last rate case resulted in a settlement agreement providing for an increase of $4.6 million in distribution base revenue and an additional step increase in revenue of $1.4 million for investments in gas mains extensions and infrastructure replacement projects, effective May 1, 2014, and a step adjustment that provided for an annual increase of $1.8 million in revenue effective May 1, 2015.

Pipeline Refund— On February 19, 2015, the FERC issued Opinion No. 524-A, the final order in Portland Natural Gas Transmission's (PNGTS) Section 4 rate case, requiring PNGTS to issue refunds to shippers. Northern Utilities received a pipeline refund of $22.0 million on April 15, 2015. As a gas supply-related refund, the entire amount refunded will be credited to Northern Utilities' customers and marketers. In New Hampshire, the refund is being credited to all customers over a three year period as directed by the NHPUC. In Maine, the refund has been divided into two parts, as directed by the MPUC. Maine retail customers who purchase their gas directly from Northern Utilities are being credited their portion of the refund over a three year period. The second part of the refund was paid on October 5, 2015 as a one-time lump sum payment directly to marketers who transport gas on Northern Utilities' distribution system. The Company has recorded current and noncurrent Regulatory Liabilities related to these refunds of $4.4 million and $2.4 million, respectively, on its Balance Sheets as of December 31, 2016.

NHPUC Energy Efficiency Resource Standard Proceeding— In May 2015, the NHPUC opened a proceeding to establish an Energy Efficiency Resource Standard ("EERS"), an energy efficiency policy with specific targets or goals for energy savings that New Hampshire electric and gas utilities must meet. On April 27, 2016, a comprehensive settlement agreement was filed by the parties, including Northern Utilities, which was approved by the NHPUC on August 2, 2016. The settlement provides for: extending the 2014-2016 Core program an additional year (through 2017); establishing an EERS; establishing a recovery mechanism to compensate the utilities for lost-revenue related to the EERS programs; and approving the performance incentives and processes for stakeholder involvement, evaluation, measurement and verification, and oversight of the EERS programs.

Litigation - The Company is also involved in other 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 its financial position, operating results or cash flows.

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 is in material compliance with applicable environmental and safety laws and regulations and, as of December 31, 2016, has not identified any material losses reasonably likely to be incurred in excess of recorded amounts. However, we cannot assure 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. 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.

Manufactured Gas Plant (MGP) Sites - Northern Utilities has an extensive program to identify, investigate and remediate former manufactured gas plant (MGP) sites, which were operated from the mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. In Maine, Northern Utilities has documented the presence of MGP sites in Lewiston and Portland, and a former MGP disposal site in Scarborough.

Northern Utilities has worked with the Maine Department of Environmental Protection (ME DEP) and New Hampshire Department of Environmental Services (NH DES) to address environmental concerns with these sites. Northern Utilities or others have substantially completed remediation of the Exeter, Rochester, Dover, Somersworth, Portsmouth, Lewiston, Portland and Scarborough sites, though on site monitoring continues and it is possible that future activities may be required.

In December 2016, the ME DEP issued a Certificate of Completion for the Portland remediation activities completed in early 2016. Pursuant to an agreement between the State of Maine and Northern Utilities, future remedial activities necessitated as a result of development of the Portland site will be primarily the responsibility of the State of Maine.

The NHPUC and MPUC have approved regulatory mechanisms for the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC has approved the recovery of MGP environmental costs over succeeding seven-year periods. For Northern Utilities' Maine division, the MPUC has authorized the recovery of environmental remediation costs over succeeding five-year periods.

The Environmental Obligations table below shows the amounts accrued for Northern Utilities related to estimated future cleanup costs 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.

Environmental Obligations

	(millions)	
	2016	2015
Total Balance at Beginning of Period	**$ 1.6**	$ 3.6
Additions	**1.8**	2.9
Less: Payments / Reductions	**1.6**	4.9
Total Balance at End of Period	**$ 1.8**	$ 1.6
Less: Current Portion	**0.3**	1.1
Noncurrent Balance at End of Period	**$ 1.5**	$ 0.5

Litigation - The Company is also involved in other 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 its financial position, operating results or cash flows.

Market Risk - Although the Company is subject to commodity price risk as part of its traditional operations, the current regulatory framework within which the Company operates allows for full collection of fuel and gas costs in rates. Consequently, there is limited commodity price risk after consideration of the related rate-making.

NOTE 6: 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, 2016, 2015 and 2014 are shown in the table below:

	($000's)		
	2016	2015	2014
Current Income Tax Provision			
Federal	**$ (5,956)**	$ ---	$ ---
State	**(367)**	2,220	(1,162)
Total Current Income Taxes	**(6,323)**	2,220	(1,162)
Deferred Income Tax Provision			
Federal	**11,415**	6,438	6,856
State	**1,778**	(404)	3,123
Total Deferred Income Taxes	**13,193**	6,034	9,979
Total Income Tax Expense	**$ 6,870**	$ 8,254	$ 8,817

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:

	2016	2015	2014
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, net	**6**	6	6
Utility Plant Differences	---	---	---
Tax Credits	---	---	---
Other, net	---	---	1
Effective Income Tax Rate	40%	40%	41%

Temporary differences which gave rise to deferred tax assets and liabilities in 2016 and 2015 are shown below:

Temporary Differences (000's)	**2016**	2015
Deferred Tax Assets		
Retirement Benefit Obligations	**$ 13,068**	$ 10,286
Net Operating Loss Carryforward	**25,676**	15,476
Tax Credit Carryforwards	**135**	---
Regulatory Assets	---	5,310
Other, net	---	---
Total Deferred Tax Assets	**$ 38,879**	$ 31,072
Deferred Tax Liabilities		
Utility Plant Differences	**$ 64,400**	$ 45,795
Regulatory Liabilities	**1,019**	1,306
Other, net	**1,483**	1,370
Total Deferred Tax Liabilities	**66,902**	48,471
Net Deferred Tax Liabilities	**$ 28,023**	$ 17,399

The Company evaluated its tax positions at December 31, 2016 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 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 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. The Company recorded no interest on tax items for the years ended December 31, 2016, 2015 and 2014.

In total at December 31, 2016, the Company had recorded federal and state net operating loss (NOL) carryforward assets of $25.7 million to offset against taxes payable in future periods. If unused, the Company's NOL carryforward assets will begin to expire in 2029.

The Company remains subject to examination by New Hampshire and Maine tax authorities for the tax periods ended December 31, 2013; December 31, 2014; and December 31, 2015. Income tax filings for the year ended December 31, 2015 have been filed with the New Hampshire Department of Revenue Administration and the Maine Revenue Service.

NOTE 7: RETIREMENT BENEFIT OBLIGATIONS

The Company co-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.
- 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 a non-qualified 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:

	2016	2015	2014
Used to Determine Plan costs for years ended December 31:			
Discount Rate	**4.30%**	4.00%	4.80%
Rate of Compensation Increase	**3.00%**	3.00%	3.00%
Expected Long-term Rate of Return on Plan Assets	**8.00%**	8.00%	8.00%
Health Care Cost Trend Rate Assumed for Next Year	**7.00%**	7.00%	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health Care Cost Trend Rate is reached	**2022**	2018	2018
Effect of 1% Increase in Health Care Cost Trend Rate ($000's)	**$ 477**	$ 488	$ 346
Effect of 1% Decrease in Health Care Cost Trend Rate ($000's)	**$ (364)**	$ (367)	$ (270)

Used to Determine Benefit Obligations at December 31:	**2016**	2015	2014
Discount Rate	**4.10%**	4.30%	4.00%
Rate of Compensation Increase	**3.00%**	3.00%	3.00%
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	7.00%	7.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%	4.00%
Year that Ultimate Health care Cost Trend Rate is reached	**2025**	2022	2018
Effect of 1% Increase in Health Care Cost Trend Rate ($000's)	**$ 6,768**	$ 5,010	$ 5,712
Effect of 1% Decrease in Health Care Cost Trend Rate ($000's)	**$(5,221)**	$(3,871)	$(4,352)

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on an assessment of current market conditions using high quality corporate bond interest rate indices and pension yield curves. The Rate of Compensation Increase assumption used in each of 2016, 2015 and 2014 was 3.00%, 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		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Service Cost	**$ 1,299**	$ 1,333	$ 1,025	**$ 1,069**	$ 1,042	$ 758	**$ 64**	$ 46	$ 21
Interest Cost	**1,519**	1,290	1,117	**992**	912	774	**154**	126	100
Expected Return on Plan Assets	**(1,857)**	(1,606)	(1,373)	**(596)**	(494)	(387)	**---**	---	---
Prior Service Cost Amortization	**241**	243	195	**431**	601	600	**76**	32	4
Transition Obligation Amortization	**---**	---	---	**---**	---	---	**---**	---	---
Actuarial Loss Amortization	**751**	735	244	**343**	445	24	**150**	125	37
Sub-total	**1,953**	1,995	1,208	**2,239**	2,506	1,769	**444**	329	162
Amounts Capitalized and Deferred	**(759)**	(738)	(435)	**(939)**	(1,012)	(698)	**---**	---	---
NPBC Recognized	**$ 1,194**	$ 1,257	$ 773	**$ 1,300**	$ 1,494	$ 1,071	**$ 444**	$ 329	$ 162

The estimated amortization related to Actuarial Loss and Prior Service Cost included in the Company's retirement plan costs or as a reduction of regulatory assets over the next fiscal year are $1.1 million, $1.0 million and $0.2 million for the Pension, PBOP and SERP plans, respectively.

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan		PBOP Plan		SERP	
	2016	2015	**2016**	2015	**2016**	2015
Change in Plan Assets:						
Plan Assets at Beginning of Year	**$ 17,887**	$ 16,034	**$ 6,213**	$ 4,928	**$ ---**	$ ---
Actual Return on Plan Assets	**733**	1,288	**245**	116	**---**	---
Employer Contributions	**1,722**	1,308	**1,434**	1,534	**14**	15
Participant Contributions	**---**	---	**31**	34	**---**	---
Benefits Paid	**(1,130)**	(743)	**(375)**	(399)	**(14)**	(15)
Plan Assets at End of Year	**$ 19,212**	$ 17,887	**$ 7,548**	$ 6,213	**$ ---**	$ ---
Change in PBO:						
PBO at Beginning of Year	**$ 27,721**	$ 23,941	$ **18,985**	$ 18,729	**$ 2,749**	$ 2,064
Service Cost	**1,299**	1,333	**1,069**	1,042	**64**	46
Interest Cost	**1,519**	1,290	**992**	912	**154**	126
Plan Amendments	**---**	474	**---**	---	**---**	232
Participant Contributions	**---**	---	**31**	34	**---**	---
Benefits Paid	**(1,130)**	(743)	**(375)**	(399)	**(14)**	(15)
Actuarial (Gain) or Loss	**1,443**	1,426	**5,173**	(1,333)	**(166)**	296
PBO at End of Year	**$ 30,852**	$ 27,721	$ **25,875**	$ 18,985	**$ 2,787**	$ 2,749
Funded Status: Assets vs PBO	**$ (11,640)**	$ (9,834)	**$ (18,327)**	$ (12,772)	**$ (2,787)**	$ (2,749)

The funded status of the Pension, PBOP and SERP Plans is calculated based on the difference between the benefit obligation and the fair value of plan assets and is recorded on the balance sheets as an asset or a liability. Because the Company recovers the retiree benefit costs from customers through rates, regulatory assets are recorded in lieu of an adjustment to Accumulated Other Comprehensive Income/(Loss).

The Company has recorded on its Balance Sheets as a liability the underfunded status of its retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets, net of tax, of $14.1 million and $10.4 million at December 31, 2016 and 2015, respectively, to recognize the future collection of these plan obligations in 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 $27.9 million and $25.0 million as of December 31, 2016 and 2015, respectively. The ABO for the SERP was $2.0 million and $2.1 million as of December 31, 2016 and 2015, respectively. For the PBOP Plan, the ABO and PBO are the same.

The Company expects to continue to make contributions to its Pension Plan in 2017 and future years at minimum required and discretionary funding levels consistent with the amounts recovered in rates for these Pension Plan costs.

The following table represents employer contributions, participant contributions and benefit payments ($000's).

	Pension Plan			PBOP Plan			SERP		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Employer Contributions	**$ 1,722**	$ 1,308	$ 1,408	**$ 1,434**	$ 1,534	$ 1,422	**$ 14**	$ 15	$ 22
Participant Contributions	**$ ---**	$ ---	$ ---	**$ 31**	$ 34	$ 36	**$ ---**	$ ---	$ ---
Benefit Payments	**$ 1,130**	$ 743	$ 1,008	**$ 375**	$ 399	$ 357	**$ 14**	$ 15	$ 22

The following table represents estimated future benefit payments ($000's).

Estimated Future Benefit Payments			
	Pension	**PBOP**	**SERP**
2017	$ 1,380	$ 477	$ 14
2018	1,255	553	13
2019	1,564	621	231
2020	1,706	735	227
2021	1,992	918	281
2022 - 2026	$ 11,913	$ 6,173	$ 1,498

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 47% in common stock equities, 37% in fixed income securities, 10% in real estate securities and 6% in a combined equity and debt fund. 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**	**Actual Allocation at December 31,**		
	2017	**2016**	**2015**	**2014**
Equity Funds	47%	**46%**	**46%**	49%
Debt Funds	37%	**37%**	**37%**	36%
Real Estate Fund	10%	**10%**	**11%**	10%
Asset Allocation Fund(1)	6%	**7%**	**6%**	5%
Total		**100%**	**100%**	100%

(1) Represents investments in an asset allocation fund. This fund invests in both equity and debt securities.

PBOP Plan	**Target Allocation**	**Actual Allocation at December 31,**		
	2017	**2016**	**2015**	**2014**
Equity Funds	55%	**55%**	53%	56%
Debt Funds	45%	**43%**	47%	44%
Other[1]	0%	**2%**	0%	0%
Total		**100%**	100%	100%

(1) Represents investments being held in cash equivalents as of December 31, 2016 pending transfer into debt and equity funds.

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.00% for 2016. 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.

Following is a description of the valuation methodologies used for assets measured at fair value. There have been no changes in the methodologies used at December 31, 2016 and 2015. Please also see Note 1 for a discussion of the Company's fair value accounting policy.

Equity, Fixed Income, Index and Asset Allocation Funds
These investments are valued based on quoted prices from active markets. These securities are categorized in Level 1 as they are actively traded and no valuation adjustments have been applied.

Cash Equivalents
These investments are valued at cost, which approximates fair value, and are categorized in Level 1.

Real Estate Fund
These investments are valued at net asset value (NAV) per unit based on a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity. In accordance with FASB Codification Topic 820, "Fair Value Measurement", these investments have not been classified in the fair value hierarchy. The fair value amounts presented in the tables below for the Real Estate Fund are intended to permit reconciliation of the fair value hierarchy to the "Plan Assets at End of Year" line item shown in the "Change in Plan Assets" table above.

Assets measured at fair value on a recurring basis for the Pension Plan as of December 31, 2016 and 2015 are as follows ($000's):

Description	Balance as of December 31,	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at Reporting Date Using			
2016				
Pension Plan Assets:				
Equity Funds	$ 8,890	$ 8,890	$ ---	$ ---
Fixed Income Funds	7,157	7,157	---	---
Asset Allocation Fund	1,302	1,302	---	---
Total Assets in the Fair Value Hierarchy	$ 17,349	$ 17,349	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	1,863			
Total Assets	$ 19,212			
2015				
Pension Plan Assets:				
Equity Funds	$ 8,231	$ 8,231	$ ---	$ ---
Fixed Income Funds	6,604	6,604	---	---
Asset Allocation Fund	1,134	1,134	---	---
Total Assets in the Fair Value Hierarchy	$ 15,969	$ 15,969	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	1,918			
Total Assets	$ 17,887			

Assets measured at fair value on a recurring basis for the PBOP Plan as of December 31, 2016 and 2015 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	Balance as of December 31,	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2016				
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$ 3,217	$ 3,217	$ ---	$ ---
Equity Funds	4,149	4,149	---	---
Total Mutual Funds	7,366	7,366	---	---
Cash Equivalents	182	182	---	---
Total Assets	$ 7,548	$ 7,548	$ ---	$ ---
2015				
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$ 2,902	$ 2,902	$ ---	$ ---
Equity Funds	3,311	3,311	---	---
Total Assets	$ 6,213	$ 6,213	$ ---	$ ---

Employee 401(k) Tax Deferred Savings Plan --- The Company co-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.

The Company's share of contributions to the 401(k) Plan was $888,000, $791,000 and $688,000 for the years ended December 31, 2016, 2015 and 2014, respectively.

NOTE 8: OPERATING REVENUES AND SALES MARGIN (unaudited)

Operating Revenues and Sales Margin – The following table details Operating Revenue and Sales Margin for the last three years:

Operating Revenues ($ millions)

				Change			
				2016 vs. 2015		2015 vs. 2014	
	2016	2015	2014	$	%	$	%
Operating Revenue	**$ 150.1**	$ 169.9	$ 164.1	$ (19.8)	(11.7%)	$ 5.8	3.5%
Cost of Gas Sales	**73.7**	93.7	91.4	(20.0)	(21.3%)	2.3	2.5%
Sales Margin	**$ 76.4**	$ 76.2	$ 72.7	$ 0.2	0.3%	$ 3.5	4.8%

The Company analyzes operating results using Sales Margin, a non-GAAP measure. Sales Margin is calculated as Operating Revenues less Cost of Gas Sales. The Company believes Sales Margin is an important measure to analyze profitability because the approved cost of sales are tracked costs that are passed through directly to the customer resulting in an equal and offsetting amount reflected in Operating Revenues. Sales Margin can be reconciled to Operating Income, a GAAP measure, by including Operation and Maintenance, Depreciation and Amortization and Taxes Other Than Income Taxes.