Summary

Unitil
Northern Utilities, Inc.

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

Summary Schedule

New Hampshire Division
Period Covered: May 1, 2011 - October 31, 2011

	Column A	Column B	Column C
1	**ANTICIPATED DIRECT COST OF GAS**		
2	**Purchased Gas:**		
3	Demand Costs:	$ 419,038	
4	Supply Costs:	$ 3,307,415	
5			
6	**Storage & Peaking Gas:**		
7	Demand, Capacity:	$ 644,179	
8	Commodity Costs:	$ 25,185	
9			
10	**Hedging (Gain)/Loss**	$ 93,792	
11			
12	**Interruptible Included Above**	$ -	
13			
14	**Capacity Release**	$ -	
15			
16	**Adjustment for Actual Costs**	$ -	
17			
18	**Total Anticipated Direct Cost of Gas**		$ 4,489,610
19			
20	**ANTICIPATED INDIRECT COST OF GAS**		
21	**Adjustments:**		
22	Prior Period Under/(Over) Collection	$ 124,276	
23	NHPUC Consultant Costs	$ 28,990	
24	Interest	$ 2,579	
25	Refunds	$ -	
26	Interruptible Margins	$ -	
27	Total Adjustments		$ 155,845
28			
29	**Working Capital:**		
30	Total Anticipated Direct Cost of Gas	$ 4,489,610	
31	Working Capital Percentage	0.190%	
32	Working Capital Allowance	$ 8,530	
33	Plus: Working Capital Reconciliation	$ (7,494)	
34			
35	Total Working Capital Allowance		$ 1,036
36			
37	**Bad Debt:**		
38	Total Anticipated Direct Cost of Gas	$ 4,489,610	
39	Plus: Prior Period Under/(Over) Collection	$ 124,276	
40	Plus: Prior Period Adjustment	$ 28,990	
41	Plus: Total Working Capital	$ 1,036	
42	Subtotal	$ 4,643,912	
43			
44	Bad Debt Percentage	0.450%	
45	Bad Debt Allowance	$ 20,898	
46	Plus: Bad Debt Reconciliation (Acct 182.22)	$ 3,159	
47	Total Bad Debt Allowance		$ 24,057
48			
49	**Local Production and Storage Capacity**		$ -
50			
51	**Miscellaneous Overhead-25.15% Allocated to Summer Season**		$ 31,261
52			
53	**Total Anticipated Indirect Cost of Gas**		$ 212,198
54			
55	**Total Cost of Gas**		$ 4,701,808
56			

NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: May 1, 2011 - October 31, 2011

Column A		**Column B**	**Column C**	
Total Anticipated Direct Cost of Gas		$ 4,489,610		
Projected Prorated Sales (05/01/11 - 10/31/11)		7,400,642		
Direct Cost of Gas Rate			$ 0.6067	per therm
Demand Cost of Gas Rate		$ 1,063,217	$ 0.1437	per therm
Commodity Cost of Gas Rate		$ 3,426,393	$ 0.4630	per therm
Total Direct Cost of Gas Rate		$ 4,489,610	$ 0.6067	per therm
Total Anticipated Indirect Cost of Gas		$ 212,198		
Projected Prorated Sales (05/01/11 - 10/31/11)		7,400,642		
Indirect Cost of Gas			$ 0.0287	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/11			**$ 0.6354**	**per therm**
RESIDENTIAL COST OF GAS RATE - 05/01/11		**COGwr**	**$ 0.6354**	**per therm**
	Maximum (COG+25%)		**$ 0.7943**	
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/11		**COGwl**	**$ 0.5697**	**per therm**
	Maximum (COG+25%)		**$ 0.7121**	
C&I HLF Demand Costs Allocated per SMBA	$ 140,596			
PLUS: Residential Demand Reallocation to C&I HLF	$ 7,901			
C&I HLF Total Adjusted Demand Costs	$ 148,497			
C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	1,834,095			
Demand Cost of Gas Rate	**$ 0.0810**			
C&I HLF Commodity Costs Allocated per SMBA	$ 844,207			
PLUS: Residential Commodity Reallocation to C&I HLF	$ (467)			
C&I HLF Total Adjusted Commodity Costs	$ 843,740			
C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	1,834,095			
Commodity Cost of Gas Rate	**$ 0.4600**			
Indirect Cost of Gas	**$ 0.0287**			
Total C&I HLF Cost of Gas Rate	**$ 0.5697**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/11		**COGwh**	**$ 0.6878**	**per therm**
	Maximum (COG+25%)		**$ 0.8598**	
C&I LLF Demand Costs Allocated per SMBA	$ 420,516			
PLUS: Residential Demand Reallocation to C&I LLF	$ 23,631			
C&I LLF Total Adjusted Demand Costs	$ 444,147			
C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	2,291,857			
Demand Cost of Gas Rate	**$ 0.1938**			
C&I LLF Commodity Costs Allocated per SMBA	$ 1,067,061			
PLUS: Residential Commodity Reallocation to C&I LLF	$ (590)			
C&I LLF Total Adjusted Commodity Costs	$ 1,066,471			
C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	2,291,857			
Commodity Cost of Gas Rate	**$ 0.4653**			
Indirect Cost of Gas	**$ 0.0287**			
Total C&I LLF Cost of Gas Rate	**$ 0.6878**			

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 2011 - October 31, 2011

	Column A	Column D
1	**ANTICIPATED DIRECT COST OF GAS**	
2	**Purchased Gas:**	
3	Demand Costs:	Schedule 1A, LN 71
4	Supply Costs:	Schedule 1B, LN 15
5		
6	**Storage & Peaking Gas:**	
7	Demand, Capacity:	Schedule 1A, LN 73
8	Commodity Costs:	Schedule 1B, LN 16 + Schedule 1B, LN 17
9		
10	**Hedging (Gain)/Loss**	Schedule 1B, LN 15
11		
12	**Interruptible Included Above**	- (Schedule 1B, LN 22)
13		
14	**Capacity Release**	- (Schedule 1A, LN 76)
15		
16	**Adjustment for Actual Costs**	
17		
18	**Total Anticipated Direct Cost of Gas**	Sum (LN 3 : LN 16)
19		
20	**ANTICIPATED INDIRECT COST OF GAS**	
21	**Adjustments:**	
22	Prior Period Under/(Over) Collection	Schedule 3, LN 108: October
23	NHPUC Consultant Costs	
24	Interest	Schedule 3, LN 115: Total
25	Refunds	Company Analysis
26	Interruptible Margins	- (Schedule 1A, LN 77)
27	Total Adjustments	Sum (LN 22 : LN 26)
28		
29	**Working Capital:**	
30	Total Anticipated Direct Cost of Gas	LN 18
31	Working Capital Percentage	2nd Rev. Pg 21 IV COG Clause 6.1
32	Working Capital Allowance	LN 30 * LN 31
33	Plus: Working Capital Reconciliation	Schedule 3, LN 85: October 2010 Summer Reconciliation
34		
35	Total Working Capital Allowance	Sum (LN 32 : LN 33)
36		
37	**Bad Debt:**	
38	Total Anticipated Direct Cost of Gas	LN 18
39	Plus: Prior Period Under/(Over) Collection	Schedule 3, LN 108: October
40	Plus: Prior Period Adjustment	
41	Plus: Total Working Capital	LN 35
42	Subtotal	Sum (LN 38 : LN 41)
43		
44	Bad Debt Percentage	2nd Rev. Pg 21 IV COG Clause 6.1
45	Bad Debt Allowance	LN 44 * LN 42
46	Plus: Bad Debt Reconciliation (Acct 182.22)	Schedule 3, LN 96: October
47	Total Bad Debt Allowance	LN 45 + LN 46
48		
49	**Local Production and Storage Capacity**	Schedule 1A, LN 84
50		
51	**Miscellaneous Overhead-25.15% Allocated to Summer Season**	Schedule 1A, LN 83
52		
53	**Total Anticipated Indirect Cost of Gas**	Sum (LN 27 : LN 51)
54		
55	**Total Cost of Gas**	LN 53 + LN 18
56		

NORTHERN UTILITIES, INC.

57		
58	CALCULATION OF FIRM SALES COST OF GAS RATE	
59	Period Covered: May 1, 2011 - October 31, 2011	
60		
61	**Column A**	**Column D**
62		
63	Total Anticipated Direct Cost of Gas	LN 18
64	Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
65	**Direct Cost of Gas Rate**	LN 63 / LN 64
66		
67	**Demand Cost of Gas Rate**	Column B : SUM (LN 3 , LN 7 , LN 14)
68	**Commodity Cost of Gas Rate**	Column B : SUM (LN 4 , LN 8 , LN 10 , LN 12)
69	**Total Direct Cost of Gas Rate**	SUM (LN 67 : LN 68)
70		
71	Total Anticipated Indirect Cost of Gas	LN 53
72	Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
73	**Indirect Cost of Gas**	LN 71 / LN 72
74		
75		
76	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/11**	LN 69 + LN 73
77		
78	**RESIDENTIAL COST OF GAS RATE - 05/01/11**	Company Analysis
79		LN 78 * 1.25
80		
81		
82	**COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/11**	Company Analysis
83		LN 82 * 1.25
84		
85	C&I HLF Demand Costs Allocated per SMBA	Schedule 10A, LN 169
86	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 23, LN 16
87	C&I HLF Total Adjusted Demand Costs	Sum (LN 85 : LN 86)
88	C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
89	**Demand Cost of Gas Rate**	LN 87 / LN 88
90		
91	C&I HLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 139
92	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 23, LN 26
93	C&I HLF Total Adjusted Commodity Costs	Sum (LN 91 : LN 92)
94	C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
95	**Commodity Cost of Gas Rate**	LN 93 / LN 94
96		
97	**Indirect Cost of Gas**	LN 73
98		
99	**Total C&I HLF Cost of Gas Rate**	Sum (LN 89, LN 95, LN 97)
100		
101		
102	**COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/11**	Company Analysis
103		LN 102 * 1.25
104		
105	C&I LLF Demand Costs Allocated per SMBA	Schedule 10A, LN 170
106	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 23, LN 17
107	C&I LLF Total Adjusted Demand Costs	Sum (LN 105 : LN 106)
108	C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
109	**Demand Cost of Gas Rate**	LN 107 / LN 108
110		
111	C&I LLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 140
112	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 23, LN 27
113	C&I LLF Total Adjusted Commodity Costs	Sum (LN 111 : LN 112)
114	C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
115	**Commodity Cost of Gas Rate**	LN 113 / LN 114
116		
117	**Indirect Cost of Gas**	LN 73
118		
119	**Total C&I LLF Cost of Gas Rate**	Sum (LN 109, LN 115, LN 117)

NORTHERN UTILTIES, INC. - NEW HAMSHIRE DIVISION
Summer 2011 Cost of Gas Filing

Table of Contents

Schedule 1

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH Division Total Annual Demand Cost Allocation

1	**Resource**	**Costs**
2	Pipeline & Product Demand	$ 2,722,994
3	Storage	$ 13,319,084
4	Peaking	$ 2,995,813
5	Total Gross Demand Cost	$ 19,037,891
6		
7	Capacity Assignment Demand Revenue Estimate	$ 2,709,073
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 19,037,891
9	Capacity Assignment as % of Total Gross Demand Cost	14.23%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 387,479
14	Storage	$ 1,895,292
15	Peaking	$ 426,301
16	Total Capacity Assignment Credit	$ 2,709,073
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,335,514
21	Storage	$ 11,423,792
22	Peaking	$ 2,569,512
23	Total Net Demand Cost (Less Capacity Assignment)	$ 16,328,818
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,489
28	Less 14.23% NH Transp. Capacity Assignment	(1,635)
29	Net Pipeline MDQ	9,854
30		
31	Net Pipeline MDQ	9,854
32	Less: Firm Sales Base Use	2,895
33	Remaining Pipeline MDQ	6,959
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$237.01
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,335,514
40	Less: Base Pipeline Use	$ 686,227
41	Remaining Pipeline Use	$ 1,649,287

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH Division Total Annual Demand Cost Allocation

1	**Resource**	
2	Pipeline & Product Demand	Schedule 21, LN 84 + Schedule 21, LN 87
3	Storage	Schedule 21, LN 85
4	Peaking	Schedule 21, LN 86
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Attachment NUI-FXW-5
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		
13	Pipeline & Product Demand	LN 2 * LN 9
14	Storage	LN 3 * LN 9
15	Peaking	LN 4 * LN 9
16	Total Capacity Assignment Credit	Sum (LN 13 : LN 15)
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		
20	Pipeline & Product Demand	LN 2 - LN 13
21	Storage	LN 3 - LN 14
22	Peaking	LN 4 - LN 15
23	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 16
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DE**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 14.23% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

42 **NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**
43 (Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)
44

Line	All Months	Nov	Dec	Jan	Feb	Mar	Apr
46	Remaining Load for All Months	2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209
47	Rank	6	4	1	2	3	5
48	% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
49	PR	3.91%	6.85%	15.73%	2.32%	3.20%	0.51%
50	CumPR	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%

51

Line	Peak Months Only	Nov	Dec	Jan	Feb	Mar	Apr
53	Remaining Load for Peak Months Only	2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209
54	Rank	6	4	1	2	3	5
55	% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
56	PR	6.67%	6.85%	15.73%	2.32%	3.20%	0.51%
57	CumPR	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%

58

59 **DEMAND COST PR ALLOCATORS**

Line		Nov	Dec	Jan	Feb	Mar	Apr
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
62	Pipeline - Remaining	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%
63	Storage & Peaking	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%
64	Capacity Release	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%
65	Interr. Margins & Off Sys Sales	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%

66

67 **DEMAND COSTS ALLOCATED TO MONTHS**

Line		Nov	Dec	Jan	Feb	Mar	Apr
69	Pipeline - Base	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186
70	Pipeline - Remaining	$ 97,412	$ 218,912	$ 569,467	$ 309,997	$ 271,710	$ 105,864
71	Total Pipeline	$ 154,598	$ 276,098	$ 626,652	$ 367,183	$ 328,896	$ 163,049
72							
73	Storage & Peaking	$ 826,492	$ 1,857,350	$ 4,831,616	$ 2,630,159	$ 2,305,313	$ 898,195
74							
75	Less Credits to Demand Cost						
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 117,579	$ 247,371	$ 621,852	$ 344,673	$ 303,773	$ 126,607
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
79							
80	Total Direct Demand Costs	$ 863,511	$ 1,886,077	$ 4,836,416	$ 2,652,669	$ 2,330,436	$ 934,637

81

Line	
82	Indirect Demand Costs/(Credits)
83	Miscellaneous Overhead
84	Local Production & Storage
85	Subtotal

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

42 **NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT**
43 (Based on NH Firm Sales Sendout for Remaining Temperatur
44

Line		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**
46	Remaining Load for All Months	764,485	190,519	28,120	90,665	282,509	920,625	25,432,233	23,155,310	2,276,922
47	Rank	8	10	12	11	9	7			
48	% Max Month	13.75%	3.43%	0.51%	1.63%	5.08%	16.56%			
49	PR	1.08%	0.18%	0.04%	0.10%	0.18%	0.40%	34.53%		
50	CumPR	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%
51										
52	**Peak Months Only**							**Total**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only							23,155,310		
54	Rank									
55	% Max Month									
56	PR							35.30%		
57	CumPR							100.00%	100.00%	0.00%

58
59 **DEMAND COST PR ALLOCATORS**

Line		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
60		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
62	Pipeline - Remaining	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%
63	Storage & Peaking	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%
64	Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

66
67 **DEMAND COSTS ALLOCATED TO MONTHS**

Line		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer	Winter	Summer
68		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**	**Winter**	**Summer**
69	Pipeline - Base	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 686,227	$ 343,114	$ 343,114	50.00%	50.00%
70	Pipeline - Remaining	$ 26,253	$ 5,345	$ 695	$ 2,382	$ 8,378	$ 32,871	$ 1,649,287	$ 1,573,363	$ 75,925	95.40%	4.60%
71	Total Pipeline	$ 83,439	$ 62,531	$ 57,881	$ 59,568	$ 65,563	$ 90,057	$ 2,335,514	$ 1,916,476	$ 419,038	82.06%	17.94%
72												
73	Storage & Peaking	$ 222,743	$ 45,349	$ 5,899	$ 20,212	$ 71,080	$ 278,895	$ 13,993,304	$ 13,349,125	$ 644,179	95.40%	4.60%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$1,761,855	$ 1,761,855	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 306,182	$ 107,880	$ 63,780	$ 79,780	$ 136,643	$ 368,952	$ 14,566,963	$ 13,503,746	$ 1,063,217	92.70%	7.30%
81												
82	Indirect Demand Costs/(Credits)											
83	Miscellaneous Overhead							$ 124,297	$ 93,036	$ 31,261	74.85%	25.15%
84	Local Production & Storage							$ 686,673	$ 686,673	$ -	100.00%	0.00%
85	Subtotal							$ 810,970	$ 779,709	$ 31,261	96.15%	3.85%

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT**	
43	(Based on NH Firm Sales Sendout for Remaining Temperatur	
44		
45	**All Months**	
46	Remaining Load for All Months	Schedule 10B, LN 80
47	Rank	Rank LN 46
48	% Max Month	LN 46 / MAX Month LN 46
49	PR	The difference between LN 48 for the month and LN 48 for next highest rank
50	CumPR	Cumulative Values, LN 49
51		
52	**Peak Months Only**	
53	Remaining Load for Peak Months Only	LN 46
54	Rank	Rank LN 53
55	% Max Month	LN 53 / MAX Month LN 53
56	PR	The difference between LN 55 for the month and LN 55 for next highest rank
57	CumPR	Cumulative Values, LN 56
58		
59	**DEMAND COST PR ALLOCATORS**	
60		
61	Pipeline - Base	1/12
62	Pipeline - Remaining	LN 50
63	Storage & Peaking	LN 50
64	Capacity Release	LN 57
65	Interr. Margins & Off Sys Sales	LN 57
66		
67	**DEMAND COSTS ALLOCATED TO MONTHS**	
68		
69	Pipeline - Base	LN 40 * LN 61
70	Pipeline - Remaining	LN 41 * LN 62
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & Peaking	LN 63 * (Sum LN 21 : LN 22)
74		
75	Less Credits to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	LN 64 * Sum (Schedule 21 LN 88, Schedule 21 LN 89)
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79		
80	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 78)
81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
	Supply Volumes - Therms							
1	New Hampshire Sales Pipeline	1,654,474	1,051,622	826,747	952,582	1,143,989	1,810,979	7,440,393
2	New Hampshire Sales Storage	0	0	0	0	0	0	0
3	New Hampshire Sales Peaking	7,586	7,518	8,283	7,538	7,141	7,221	45,287
4	Total New Hampshire Firm Sales Sendout	1,662,060	1,059,140	835,030	960,120	1,151,130	1,818,200	7,485,680
5								
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0
7								
8	Total Firm Sendout	1,662,060	1,059,140	835,030	960,120	1,151,130	1,818,200	7,485,680
9	Total Firm Sales	1,645,185	1,046,679	825,723	948,437	1,136,884	1,797,734	7,400,642
10	Difference (LAUF & Company Use)	16,875	12,461	9,307	11,683	14,246	20,466	85,038
11	Percent Difference	1.02%	1.18%	1.11%	1.22%	1.24%	1.13%	1.14%
12								
13	**Variable Costs**							
14	New Hampshire Sales Pipeline Commodity	$ 717,600	$ 459,176	$ 366,235	$ 425,680	$ 513,132	$ 825,592	$ 3,307,415
15	New Hampshire Hedging (Gains) Losses	$ 58,012	$ -	$ -	$ -	$ -	$ 35,780	$ 93,792
16	New Hampshire Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	New Hampshire Total Peaking	$ 3,872	$ 3,993	$ 4,561	$ 4,282	$ 4,164	$ 4,314	$ 25,185
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Total New Hampshire Sales Variable Costs	$ 779,484	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 865,685	$ 3,426,393
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 721,472	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 829,905	$ 3,332,601
21								$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 779,484	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 865,685	$ 3,426,393
24								
25	**Supply Cost/Therm**							
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.4337	$ 0.4366	$ 0.4430	$ 0.4469	$ 0.4485	$ 0.4559	$ 0.4445
27	New Hampshire Hedging (Gains) Losses	$ 0.0351	$ -	$ -	$ -	$ -	$ 0.0198	$ 0.0126
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.5104	$ 0.5311	$ 0.5506	$ 0.5681	$ 0.5831	$ 0.5973	$ 0.5561
30	New Hampshire Inventory Finance Costs per Dth Stor and F	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.4690	$ 0.4373	$ 0.4441	$ 0.4478	$ 0.4494	$ 0.4761	$ 0.4577
32								
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34								
35	**Commodity Costs**							
36	Base Commodity, therms	897,575	868,621	806,910	869,455	868,621	897,575	5,208,758
37	Base Commodity Cost Excld Hedging	$ 389,308	$ 379,271	$ 357,448	$ 388,533	$ 389,617	$ 409,188	$ 2,313,365
38	Base Hedging Commodity Cost	$ 31,473	$ -	$ -	$ -	$ -	$ 17,733	$ 49,206
39	Remaining Commodity Excld Hedging	$ 332,164	$ 83,898	$ 13,348	$ 41,429	$ 127,679	$ 420,717	$ 1,019,236
40	Remaining Hedging Commodity	$ 26,540	$ -	$ -	$ -	$ -	$ 18,046	$ 44,586
41	Total Commodity Excld Hedging	$ 721,472	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 829,905	$ 3,332,601
42	Total Hedging	$ 58,012	$ -	$ -	$ -	$ -	$ 35,780	$ 93,792
43	Total Commodity (Incl Hedging)	$ 779,484	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 865,685	$ 3,426,393

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Schedule 22, LN 9 * LN 60 * 10
2	New Hampshire Sales Storage	Schedule 22, LN 3 * LN 60 * 10
3	New Hampshire Sales Peaking	Schedule 22, LN 4 * LN 60 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Schedule 22, LN 7 * 10
7		
8	Total Firm Sendout	LN 4
9	Total Firm Sales	Schedule 10B, LN 11
10	Difference (LAUF & Company Use)	LN 8 - LN 9
11	Percent Difference	LN 10 / LN 8
12		
13	**Variable Costs**	
14	New Hampshire Sales Pipeline Commodity	Schedule 22, LN 74 * 10
15	New Hampshire Hedging (Gains) Losses	Schedule 22, LN 75 * 10
16	New Hampshire Total Storage	Schedule 22, LN 76 * 10
17	New Hampshire Total Peaking	Schedule 22, LN 77 * 10
18	New Hampshire Inventory Finance Charge	Schedule 22, LN 80 * 10
19	Total New Hampshire Sales Variable Costs	Sum LN 14 : LN 18
20	Total New Hampshire Sales Variable Costs Excld Hedges	LN 19 - LN 15
21		
22	New Hampshire Interruptible Commodity Costs	Schedule 22, LN 78
23	Total New Hampshire Commodity Costs	LN 19
24		
25	**Supply Cost/Therm**	
26	New Hampshire Sales Pipeline Commodity Excld Hedges	LN 14 / LN 1
27	New Hampshire Hedging (Gains) Losses	LN 15 / LN 1
28	New Hampshire Storage Excld Inventory Finance Costs	LN 16 / LN 2
29	New Hampshire Peaking Excld Inventory Finance Costs	LN 17 / LN 3
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	LN 18 / Sum (LN 2 : LN 3)
31	Weighted Average Cost per Dth Sendout	LN 19 / LN 8
32		
33	New Hampshire Interruptible Cost / Therm	LN 22 / LN 6
34		
35	**Commodity Costs**	
36	Base Commodity, therms	Schedule 10B, LN 64
37	Base Commodity Cost Excld Hedging	Min (LN 26 * LN 36), LN 19
38	Base Hedging Commodity Cost	Min (LN 27 * LN 36), (LN 19 - LN 37)
39	Remaining Commodity Excld Hedging	LN 20 - LN 37
40	Remaining Hedging Commodity	LN 15 - LN 38
41	Total Commodity Excld Hedging	LN 37 + LN 39
42	Total Hedging	LN 38 + LN 40
43	Total Commodity (Incl Hedging)	LN 41 + LN 42

Schedule 2

Northern Utilities, Inc.

Estimated Delivered City-Gate Commodity Costs and Volumes			
May 2011 through October 2011			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Chicago	$4,855,157	943,562	$5.1456
PNGTS	$736,769	142,882	$5.1565
Tennessee Production	$814,815	156,831	$5.1955
Niagara	$688,111	131,446	$5.2349
LNG	$46,100	8,280	$5.5677
Total System	$7,140,953	1,383,001	$5.1634

Schedule 3

Northern Utilities, Inc.

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

			Winter						Summer						
	Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
2	Residential Heat & Non Heat								786,450	453,723	435,582	384,597	467,364	746,974	3,274,690
3	Sales HLF Classes								322,617	283,547	244,765	312,352	308,414	362,399	1,834,095
4	Sales LLF Classes								536,118	309,409	145,375	251,488	361,106	688,360	2,291,857
5	Total								1,645,185	1,046,679	825,723	948,437	1,136,884	1,797,734	7,400,642
6	Rates														
7	Residential Heat & Non Heat CGA								$0.6354	$0.6354	$0.6354	$0.6354	$0.6354	$0.6354	
8	Sales HLF Classes CGA								$0.5697	$0.5697	$0.5697	$0.5697	$0.5697	$0.5697	
9	Sales LLF Classes CGA								$0.6878	$0.6878	$0.6878	$0.6878	$0.6878	$0.6878	
10	Revenues														
11	Residential Heat & Non Heat								$ (499,710)	$ (288,295)	$ (276,769)	$ (244,373)	$ (296,963)	$ (474,627)	$ (2,080,738)
12	Sales HLF Classes								$ (183,795)	$ (161,537)	$ (139,443)	$ (177,947)	$ (175,703)	$ (206,459)	$ (1,044,884)
13	Sales LLF Classes								$ (368,742)	$ (212,812)	$ (99,989)	$ (172,973)	$ (248,369)	$ (473,454)	$ (1,576,339)
14	Total Sales								$ (1,052,247)	$ (662,644)	$ (516,201)	$ (595,293)	$ (721,035)	$ (1,154,540)	$ (4,701,961)
15															

			Winter						Summer						
16															
17	**Gas Costs and Credits**		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18		Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline								$ 69,840	$ 69,840	$ 69,840	$ 69,840	$ 69,840	$ 69,840	$ 419,038
21	Storage								$ 86,802	$ 86,802	$ 86,802	$ 86,802	$ 86,802	$ 86,802	$ 520,813
22	Peaking								$ 20,561	$ 20,561	$ 20,561	$ 20,561	$ 20,561	$ 20,561	$ 123,365
24	Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 177,203	$ 177,203	$ 177,203	$ 177,203	$ 177,203	$ 177,203	$ 1,063,217
25	NUI Commodity Costs														
26	NUI Total Pipeline Volumes								304,244	188,838	139,235	176,289	216,266	349,849	1,374,721
27	Pipeline Costs Modeled in Sendout™								$ 1,549,919	$ 961,254	$ 715,227	$ 911,185	$ 1,119,926	$ 1,837,342	$ 7,094,853
28	NYMEX Price Used for Forecast								$ 4.7070	$ 4.7390	$ 4.7910	$ 4.8160	$ 4.8210	$ 4.8690	
29	NYMEX Price Used for Update								$ 3.9500	$ 4.0150	$ 4.0840	$ 4.1160	$ 4.1280	$ 4.1760	
30	Increase/(Decrease) NYMEX Price								$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	
31	Increase/(Decrease) in Pipeline Costs								$ (230,313)	$ (136,719)	$ (98,439)	$ (123,402)	$ (149,872)	$ (242,445)	
32	Updated Pipeline Costs								$ 1,319,606	$ 824,535	$ 616,788	$ 787,783	$ 970,054	$ 1,594,896	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 4.34	$ 4.37	$ 4.43	$ 4.47	$ 4.49	$ 4.56	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 1,319,606	$ 824,535	$ 616,788	$ 787,783	$ 970,054	$ 1,594,896	
37	New Hampshire Allocated Percentage								54.38%	55.69%	59.38%	54.04%	52.90%	51.76%	
38	NH Updated Pipeline Costs								$ 717,600	$ 459,176	$ 366,235	$ 425,680	$ 513,132	$ 825,592	$ 3,307,415
39	Hedging (Gain)/Loss Estimate														
40	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
41	NYMEX NG Futures Contracts								14	0	0	0	0	9	
42	Average Purchase Price								$ 4.7120	$ -	$ -	$ -	$ -	$ 4.9440	
43	NYMEX Price Used for Forecast								$ 4.7070	$ 4.7390	$ 4.7910	$ 4.8160	$ 4.8210	$ 4.8690	
44	NYMEX Price Used for Update								$ 3.9500	$ 4.0150	$ 4.0840	$ 4.1160	$ 4.1280	$ 4.1760	
45	Increase/(Decrease) NYMEX Price								(0.7570)	(0.7240)	(0.7070)	(0.7000)	(0.6930)	(0.6930)	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ 106,680	$ -	$ -	$ -	$ -	$ 69,120	$ 175,800
47	New Hampshire Allocated Percentage								54.38%	55.69%	59.38%	54.04%	52.90%	51.76%	
48	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 58,012	$ -	$ -	$ -	$ -	$ 35,780	$ 93,792
49	Price Triggered NYMEX Contracts (NH Only)														
50	NYMEX NG Futures Contracts								0	0	0	0	0	0	
51	Average Purchase Price								$ -	$ -	$ -	$ -	$ -	$ -	
52	NYMEX Price Used for Forecast								$ 4.7070	$ 4.7390	$ 4.7910	$ 4.8160	$ 4.8210	$ 4.8690	
53	NYMEX Price Used for Update								$ 3.9500	$ 4.0150	$ 4.0840	$ 4.1160	$ 4.1280	$ 4.1760	
54	Increase/(Decrease) NYMEX Price								(0.7570)	(0.7240)	(0.7070)	(0.7000)	(0.6930)	(0.6930)	
55	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	New Hampshire Allocated Percentage								100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
57	NH Futures Hedging (Gain)/Loss, Price Triggered								$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	NH Commodity Costs														
59	Pipeline Excl Hedging								$ 717,600	$ 459,176	$ 366,235	$ 425,680	$ 513,132	$ 825,592	$ 3,307,415
60	Hedging (Gain)/Loss Estimate								$ 58,012	$ -	$ -	$ -	$ -	$ 35,780	$ 93,792
61	Storage								$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Peaking								$ 3,872	$ 3,993	$ 4,561	$ 4,282	$ 4,164	$ 4,314	$ 25,185
63	Total Commodity Costs								$ 779,484	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 865,685	$ 3,426,393

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

64	Inventory Finance Charge													$ -
65	Asset Management and Capacity Release													
66	NUI AMA Revenue													$ -
67	PNGTS Litigation Cost													$ -
68	NUI Capacity Release													$ -
69	NUI AMA Rev & Cap. Release Subtotal													$ -
70	NH AMA Revenue													$ -
71	NH Capacity Release													$ -
72	NH Total Asset Management and Capacity Release		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73														
74	**Total Anticipated Direct Cost of Gas**		$ -	$ -	$ -	$ -	$ -	$ -	$ 956,687	$ 640,372	$ 547,999	$ 607,165	$ 694,499	$ 1,042,888	$ 4,489,610
75			Winter						Summer						
76			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 956,687	$ 640,372	$ 547,999	$ 607,165	$ 694,499	$ 1,042,888	$ 4,489,610
80	Working Capital Percentage		0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	
81	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -	$ -	$ 1,818	$ 1,217	$ 1,041	$ 1,154	$ 1,320	$ 1,981	$ 8,530
82	Beginning Period Working Capital Balance		$ (7,494)	$ (7,508)	$ (7,522)	$ (7,536)	$ (7,551)	$ (7,565)	$ (7,579)	$ (5,774)	$ (4,567)	$ (3,534)	$ (2,385)	$ (1,069)	
83	End of Period Working Capital Allowance		$ (7,494)	$ (7,508)	$ (7,522)	$ (7,536)	$ (7,551)	$ (7,565)	$ (5,761)	$ (4,557)	$ (3,526)	$ (2,380)	$ (1,066)	$ 912	
84	Interest		$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (13)	$ (10)	$ (8)	$ (6)	$ (3)	$ (0)	$ (124)
85	End of period with Interest	$ (7,494)	$ (7,508)	$ (7,522)	$ (7,536)	$ (7,551)	$ (7,565)	$ (7,579)	$ (5,774)	$ (4,567)	$ (3,534)	$ (2,385)	$ (1,069)	$ 912	
86	Bad Debt														
87	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 956,687	$ 640,372	$ 547,999	$ 607,165	$ 694,499	$ 1,042,888	$ 4,489,610
88	Prior Period Over/Under Collection	$ 124,276	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124,276
89	Working Capital Allowance		$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ 1,193	$ 592	$ 417	$ 529	$ 695	$ 1,357	$ 1,036
90	Subtotal	$ 124,276	$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ 957,880	$ 640,964	$ 548,415	$ 607,695	$ 695,194	$ 1,044,245	$ 4,614,922
91	Bad Debt Percentage	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	
92	Bad Debt Allowance	$ 559	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ 4,310	$ 2,884	$ 2,468	$ 2,735	$ 3,128	$ 4,699	$ 20,767
93	Beginning Period Bad Debt Balance		$ 3,159	$ 3,162	$ 3,165	$ 3,168	$ 3,172	$ 3,175	$ 3,178	$ 7,498	$ 10,400	$ 12,889	$ 15,651	$ 18,812	
94	End of Period Bad Debt Balance		$ 3,156	$ 3,159	$ 3,162	$ 3,166	$ 3,169	$ 3,172	$ 7,488	$ 10,383	$ 12,868	$ 15,624	$ 18,779	$ 23,511	
95	Interest		$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 10	$ 17	$ 22	$ 27	$ 32	$ 40	$ 184
96	End of Period Bad Debt Balance with Interest	$ 3,159	$ 3,162	$ 3,165	$ 3,168	$ 3,172	$ 3,175	$ 3,178	$ 7,498	$ 10,400	$ 12,889	$ 15,651	$ 18,812	$ 23,551	
97	Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	NHPUC Consultant Costs		$ 15,874	$ 7,611	$ 5,505										
99	Miscellaneous Overhead								$ 5,210	$ 5,210	$ 5,210	$ 5,210	$ 5,210	$ 5,210	$ 31,261
100	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
101	Beginning Balance Over/Under Collection		$ 124,276	$ 140,399	$ 148,282	$ 154,072	$ 154,362	$ 154,653	$ 154,945	$ 64,802	$ 47,846	$ 84,979	$ 102,238	$ 81,085	
102	Net Costs - Revenues		$ 15,874	$ 7,611	$ 5,505	$ -	$ -	$ -	$ (90,351)	$ (17,062)	$ 37,008	$ 17,082	$ (21,326)	$ (106,443)	
103	Ending Balance before Interest		$ 140,150	$ 148,010	$ 153,787	$ 154,072	$ 154,362	$ 154,653	$ 64,595	$ 47,739	$ 84,854	$ 102,061	$ 80,912	$ (25,358)	
104	Average Balance		$ 132,213	$ 144,204	$ 151,034	$ 154,072	$ 154,362	$ 154,653	$ 109,770	$ 56,271	$ 66,350	$ 93,520	$ 91,575	$ 27,863	
105	Interest Rate		2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	
106	Interest Expense		$ 249	$ 272	$ 285	$ 291	$ 291	$ 292	$ 207	$ 106	$ 125	$ 176	$ 173	$ 53	$ 2,519
108	Ending Balance Incl Interest Expense	$ 124,276	$ 140,399	$ 148,282	$ 154,072	$ 154,362	$ 154,653	$ 154,945	$ 64,802	$ 47,846	$ 84,979	$ 102,238	$ 81,085	$ (25,306)	
109	**Total Over/Under Collection Ending Balance**	$ 119,941	$ 136,053	$ 143,925	$ 149,704	$ 149,983	$ 150,263	$ 150,544	$ 66,526	$ 53,678	$ 94,335	$ 115,503	$ 98,827	$ (843)	
110															
111	**Total Indirect Cost of Gas**	$ 120,500	$ 238	$ 261	$ 274	$ 280	$ 280	$ 281	$ 11,543	$ 9,424	$ 8,859	$ 9,296	$ 9,860	$ 11,983	$ 183,078
112															
113	**Total Cost of Gas**	$ 120,500	$ 238	$ 261	$ 274	$ 280	$ 280	$ 281	$ 968,230	$ 649,796	$ 556,857	$ 616,461	$ 704,359	$ 1,054,871	$ 4,672,688
114															
115	**Total Interest**	$ -	$ 241	$ 264	$ 277	$ 282	$ 283	$ 283	$ 204	$ 113	$ 139	$ 198	$ 202	$ 92	$ 2,579

ıarges to NU-NH
mar in GSGT Rate Case

Line	Invoice No.	Date	Paid Date	Amount	
1	11365	9/28/2010	11/1/2010	$6,575.00	
2	11372	10/27/2010	11/1/2010	$11,902.16	
3	11385	11/23/2010	12/13/2010	$8,859.25	
4	11391	1/4/2011	1/6/2011	$6,407.90	
5				$33,744.31	
7	**To Capacity Assignment:**				
8	Recovery Rate ($ per Dth)			$ 1.17	
9	NUI-NH Pipeline & Storage MDQ Assigned (Dth)			4,069	
10	NHPUC Consultant Costs Allocated to Capacity Assignment			$4,754.68	14.09%
12	NHPUC Consultant Costs Allocated to Retail Customers			$28,989.63	85.91%
14	**To Retail Customers:**				
15			Month	Amount	
16			November	$15,873.67	
17			December	$7,610.95	
18			January	$5,505.01	
19	NHPUC Consultant Costs Allocated to Retail Customers			$28,989.63	85.91%

Schedule 4

Northern Utilities, Inc.

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 5

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.

Pipeline Contract Demand Cost Estimates

November 1, 2010 through October 31, 2011

Pipeline	Contract ID	Rate	Negotiated Rate	MDQ	Dth / GJ	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Currency	Months Per Year	Support for Demand Rate	Note	Monthly Demand	Annual Demand
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	286	Dth	Centerville, NJ	Taunton, MA	$ 5.9771	USD	12	FXW-5A, Page 1		$ 1,709	$ 20,513
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	965	Dth	Lambertville, NJ	Taunton, MA	$ 5.9771	USD	12	FXW-5A, Page 1		$ 5,768	$ 69,215
Algonquin	93002F	AFT-1 (AFT-2)	No	4,211	Dth	Mendon, MA	Brockton, MA	$ 6.1138	USD	12	FXW-5A, Page 2		$ 25,745	$ 308,943
Granite	10-010-FT-NN	FT-NN	No	100,000	Dth	NA	NA	$ 1.6666	USD	2	FXW-5A, Page 3	1	$ 166,660	$ 333,320
Granite	10-010-FT-NN	FT-NN	No	100,000	Dth	NA	NA	$ 3.5518	USD	10	FXW-5A, Page 4	1	$ 355,180	$ 3,551,800
Iroquois	R181001	RTS-1	No	6,569	Dth	Zone 1	Zone 1	$ 6.5971	USD	12	FXW-5A, Page 5		$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Dth	Pittsburgh	GSGT	$ 27.4017	USD	1	FXW-5A, Page 6	2	$ 30,142	$ 30,142
PNGTS	1997-003	FT	No	1,100	Dth	Pittsburgh	GSGT	$ 40.2456	USD	11	FXW-5A, Page 7	2	$ 44,270	$ 486,972
PNGTS	1997-004	FT	Yes	33,000	Dth	Pittsburgh	GSGT	$ 52.0632	USD	1	FXW-5A, Page 6	3	$ 1,718,086	$ 1,718,086
PNGTS	1997-004	FT	Yes	33,000	Dth	Pittsburgh	GSGT	$ 76.4666	USD	4	FXW-5A, Page 7	3	$ 2,523,398	$ 10,093,591
Tennessee	5083	FT-A	No	4,605	Dth	Zone 0	Zone 6	$ 16.5900	USD	12	FXW-5A, Page 8		$ 76,397	$ 916,763
Tennessee	5083	FT-A	No	8,550	Dth	Zone L	Zone 6	$ 15.1500	USD	12	FXW-5A, Page 8	4	$ 129,533	$ 1,554,390
Tennessee	5265	FT-A	No	2,653	Dth	Zone 4	Zone 6	$ 5.8900	USD	12	FXW-5A, Page 8		$ 15,626	$ 187,514
Tennessee	5292	FT-A	No	1,406	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 6,932	$ 83,179
Tennessee	39735	FT-A	No	929	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 4,580	$ 54,960
Tennessee	41099	FT-A	No	4,267	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 21,036	$ 252,436
Tennessee	46314	FT-A	No	950	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 4,684	$ 56,202
Tennessee	31861	NET-284	No	1,382	Dth	3	3	$ 5.0700	USD	12	FXW-5A, Page 9	5	$ 7,007	$ 84,081
Tennessee	31861	NET-284	No	844	Dth	3	4	$ 10.6100	USD	12	FXW-5A, Page 9	5	$ 8,955	$ 107,458
Texas Eastern	800384	FT-1	No	965	Dth	M3	M3	$ 5.8080	USD	12	FXW-5A, Page 10 & 20	6	$ 5,605	$ 67,257
Texas Eastern	800436	CDS	No	64	Dth	M3	M3	$ 5.3710	USD	12	FXW-5A, Page 10		$ 344	$ 4,125
Texas Eastern	800464	CDS	No	33	Dth	ELA	M1	$ 2.3750	USD	12	FXW-5A, Page 10	7	$ 78	$ 941
Texas Eastern	800464	CDS	No	9	Dth	ETX	M1	$ 2.1890	USD	12	FXW-5A, Page 10	7	$ 20	$ 236
Texas Eastern	800464	CDS	No	16	Dth	STX	M1	$ 6.8120	USD	12	FXW-5A, Page 10	7	$ 109	$ 1,308
Texas Eastern	800464	CDS	No	18	Dth	WLA	M1	$ 2.8280	USD	12	FXW-5A, Page 10	7	$ 51	$ 611
Texas Eastern	800464	CDS	No	59	Dth	M1	M3	$ 11.2800	USD	12	FXW-5A, Page 10	7	$ 666	$ 7,986
TransCanada	29594	FT	No	6,264	GJ	Dawn	Iroquois	$ 11.6124	CAD	12	FXW-5A, Page 11 & 12	8	$ 69,103	$ 829,238
TransCanada	33322	FT	No	35,872	GJ	Dawn	E. Hereford	$ 18.7330	CAD	12	FXW-5A, Page 11 & 12	9	$ 638,391	$ 7,660,696
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Dth	Alliance	Dawn	$ 7.6042	USD	12	FXW-5A, Page 13		$ 130,579	$ 1,566,952
Vector	CRL-NUI-0727	FT-1	Yes	17,086	Dth	W-10	Dawn	$ 4.5625	USD	5	FXW-5A, Page 14		$ 77,955	$ 389,774
Vector	FT-1-NUI-0122	FT-1	Yes	6,070	Dth	Alliance	St. Clair	$ 7.7745	USD	12	FXW-5A, Page 15 & 16	10	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,404	GJ	St. Clair	Dawn	$ 0.4623	CAD	12	FXW-5A, Page 17		$ 2,813	$ 33,750

Total Annual Demand Costs $ 31,558,769

Exchange Rate (CAD/USD) = 0.95 FXW-5A, Page 18

Note 1: Granite filed new rates under FERC docket RP10-896. New Granite rates projected to take effect on 1/1/2011.
Note 2: PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.
Note 3: Seasonal Recourse Rate. PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.
Note 4: The demand rate applied for Zone L to Zone 6 transportation capacity Zone 1 to Zone 6 demand rate.
Note 5: The rate is the Segment 3 demand rate of $5.07 per Dth plus the Segment 4 demand rate of $5.54 per Dth.
Note 6: For Contract ID 800384, Northern pays both the FT-1 Reservation Charge of $5.148 (Page 10 of FXW-5A) and the FT-1/FTS Other Transportation Services charge of $0.66 (Page 20 of FXW-5A).
Note 7: Rate is expressed in the tariff sheet as as a Delivery Zone of AAB ("Access Area Boundary"). The AAB is the border between the Access Areas (ETX, ELA, WLA, and STX) and the M1 Zone.
Note 8: Rate is the Delivery Pressure Toll for deliveries into Iroquois of $CAD 0.78572 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to Iroquois of $CAD 10.82669 (Page 12 of FXW-5A).
Note 9: Rate is the Delivery Pressure Toll for deliveries into E. Hereford of $CAD 1.96558 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to E. Hereford of $CAD 16.76744 (Page 12 of FXW-5A).
Note 10: Maximum tariff rate of $7.7745 (Page 15 of FXW-5A) exceeds negotiated rate of $8.0908 (Page 16 of FXW-5A). Therefore, Maximum tariff rate applies.

Northern Utilities, Inc.

Pipeline Contract Demand Cost Allocations

November 1, 2009 through October 31, 2010

Pipeline	Contract ID	MDQ	Dth / GJ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Monthly Demand	Monthly Pipeline Allocated Cost	Monthly Storage Allocated Cost	Monthly Peaking Allocated Cost	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Algonquin	93201A1C	286	Dth	201	85		70%	30%	0%	$ 1,709	$ 1,201	$ 508	$ -	$ 20,513	$ 14,417	$ 6,097	$ -
Algonquin	93201A1C	965	Dth	965			100%	0%	0%	$ 5,768	$ 5,768	$ -	$ -	$ 69,215	$ 69,215	$ -	$ -
Algonquin	93002F	4,211	Dth	4,211			100%	0%	0%	$ 25,745	$ 25,745	$ -	$ -	$ 308,943	$ 308,943	$ -	$ -
Granite	10-010-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 166,660	$ 39,825	$ 59,123	$ 67,712	$ 333,320	$ 79,650	$ 118,245	$ 135,425
Granite	10-010-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 355,180	$ 84,874	$ 126,000	$ 144,306	$ 3,551,800	$ 848,738	$ 1,260,001	$ 1,443,061
Iroquois	R181001	6,569	Dth	6,569			100%	0%	0%	$ 43,336	$ 43,336	$ -	$ -	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 30,142	$ 30,142	$ -	$ -	$ 30,142	$ 30,142	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 44,270	$ 44,270	$ -	$ -	$ 486,972	$ 486,972	$ -	$ -
PNGTS	1997-004	33,000	Dth		33,000		0%	100%	0%	$ 1,718,086	$ -	$ 1,718,086	$ -	$ 1,718,086	$ -	$ 1,718,086	$ -
PNGTS	1997-004	33,000	Dth		33,000		0%	100%	0%	$ 2,523,398	$ -	$ 2,523,398	$ -	$ 10,093,591	$ -	$ 10,093,591	$ -
Tennessee	5083	4,605	Dth	4,605			100%	0%	0%	$ 76,397	$ 76,397	$ -	$ -	$ 916,763	$ 916,763	$ -	$ -
Tennessee	5083	8,550	Dth	8,550			100%	0%	0%	$ 129,533	$ 129,533	$ -	$ -	$ 1,554,390	$ 1,554,390	$ -	$ -
Tennessee	5265	2,653	Dth		2,653		0%	100%	0%	$ 15,626	$ -	$ 15,626	$ -	$ 187,514	$ -	$ 187,514	$ -
Tennessee	5292	1,406	Dth	1,406	-		100%	0%	0%	$ 6,932	$ 6,932	$ -	$ -	$ 83,179	$ 83,179	$ -	$ -
Tennessee	39735	929	Dth	929	-		100%	0%	0%	$ 4,580	$ 4,580	$ -	$ -	$ 54,960	$ 54,960	$ -	$ -
Tennessee	41099	4,267	Dth	4,267	-		100%	0%	0%	$ 21,036	$ 21,036	$ -	$ -	$ 252,436	$ 252,436	$ -	$ -
Tennessee	46314	950	Dth	950	-		100%	0%	0%	$ 4,684	$ 4,684	$ -	$ -	$ 56,202	$ 56,202	$ -	$ -
Tennessee	31861	1,382	Dth	1,382			100%	0%	0%	$ 7,007	$ 7,007	$ -	$ -	$ 84,081	$ 84,081	$ -	$ -
Tennessee	31861	844	Dth	844			100%	0%	0%	$ 8,955	$ 8,955	$ -	$ -	$ 107,458	$ 107,458	$ -	$ -
Texas Eastern	800384	965	Dth	965	-		100%	0%	0%	$ 5,605	$ 5,605	$ -	$ -	$ 67,257	$ 67,257	$ -	$ -
Texas Eastern	800436	64	Dth	64	-		100%	0%	0%	$ 344	$ 344	$ -	$ -	$ 4,125	$ 4,125	$ -	$ -
Texas Eastern	800464	33	Dth	33			100%	0%	0%	$ 78	$ 78	$ -	$ -	$ 941	$ 941	$ -	$ -
Texas Eastern	800464	9	Dth	9			100%	0%	0%	$ 20	$ 20	$ -	$ -	$ 236	$ 236	$ -	$ -
Texas Eastern	800464	16	Dth	16			100%	0%	0%	$ 109	$ 109	$ -	$ -	$ 1,308	$ 1,308	$ -	$ -
Texas Eastern	800464	18	Dth	18			100%	0%	0%	$ 51	$ 51	$ -	$ -	$ 611	$ 611	$ -	$ -
Texas Eastern	800464	59	Dth	59			100%	0%	0%	$ 666	$ 666	$ -	$ -	$ 7,986	$ 7,986	$ -	$ -
TransCanada	29594	6,264	GJ	6,264	-		100%	0%	0%	$ 69,103	$ 69,103	$ -	$ -	$ 829,238	$ 829,238	$ -	$ -
TransCanada	33322	35,872	GJ		35,872		0%	100%	0%	$ 638,391	$ -	$ 638,391	$ -	$ 7,660,696	$ -	$ 7,660,696	$ -
Vector	CRL-NUI-0725	17,172	Dth		17,172		0%	100%	0%	$ 130,579	$ -	$ 130,579	$ -	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086	Dth		17,086		0%	100%	0%	$ 77,955	$ -	$ 77,955	$ -	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	Dth	6,070	-		100%	0%	0%	$ 47,191	$ 47,191	$ -	$ -	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,404	GJ	6,404	-		100%	0%	0%	$ 2,813	$ 2,813	$ -	$ -	$ 33,750	$ 33,750	$ -	$ -
Annual Total Demand Costs										$ 6,161,947	$ 660,263	$ 5,289,666	$ 212,018	$ 31,558,769	$ 6,979,327	$ 23,000,956	$ 1,578,485

Northern Utilities, Inc.

Storage Contract Demand Cost Estimates

November 1, 2010 through October 31, 2011

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0185	$ 1.1500	12	FXW-5A, Page 19	$ 9,677	$ 57,573	$ 58,553	$ 116,126
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.6020	12	FXW-5A, Page 20	$ 133	$ 189	$ 1,412	$ 1,601
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	FXW-5A, Page 20	$ 99	$ 497	$ 687	$ 1,184
W-10	01052	Storage	Yes	3,400,000		34,000			12	FXW-5A, Page 21	$ 240,833	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges				$ 3,008,911
MSQ = Maximum Space Quantity	13.1103545	8.01319821		24.88671576
MDWQ = Maximum Daily Withdrawal Quantity				

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2010 through October 31, 2011

Resource	Contract Quantity	Maximum Daily Quantity	Contract Quantity Demand Rate	MDQ Demand Rate	Months Per Year	Support for Demand Rates	Annual CQ Demand Cost	Annual MDQ Demand Cost	Monthly Fixed Charges	Annual Fixed Charges
Peaking Supply 1	755,000	5,000	$ -	$ 44.09	12	FXW-5A, Page 22	$ -	$ 2,645,238	$ 220,437	$ 2,645,238
Peaking Supply 2	1,435,000	57,400	$ 1.3500	$ -	5	FXW-5A, Page 23	$ 1,937,250	$ -	$ 387,450	$ 1,937,250
Total Peaking Supply Contract Demand Costs										$ 4,582,488

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2010 through October 31, 2011

Asset Management Agreeement Revenue	
Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	$ (442,000)
Wash 10 via Vector, TCPL, PNGTS	$ (1,100,000)
PNGTS Contract 1997-003	$ (30,000)
Tennessee Niagara	$ (100,000)
Tennessee Long-Haul	$ (835,000)
Total Asset Management	$ (2,507,000)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (66,701)
AGT Contract 93201A1C	$ (98,779)
Tennessee 5265	$ (259,050)
Total Capacity Release	$ (424,530)

Total Asset Management and Capacity Release Revenue	$ (2,931,530)

ALGONQUIN GAS TRANSMISSION, LLC
DISCOUNTED RATE LETTER - SCHEDULE

Customer Name	Contract No.	Contract Term	Rate Schedule	Discounted Rate	Recourse Reservation Rate	Recourse Usage Rate
NORTHERN UTILITIES, INC.	93201A1C	12/1/1997 - 10/31/2012	AFT-12	5.97710	6.58540	0.01120

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2009

•RATE SCHEDULE AFT-1

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-2/F-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-4)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(STB/SS-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(FTP)	$11.8368	$0.0019	$0.0019	$0.3911	$0.0019	$0.3892
(PSS-T)	$ 9.7854	$0.0019	$0.0019	$0.3236	$0.0019	$0.3217
(AFT-2)	$ 6.1138	$0.0019	$0.0019	$0.2029	$0.0019	$0.2010
(AFT-3)	$10.7554	$0.0019	$0.0019	$0.3555	$0.0019	$0.3536
(AFT-5)	$12.6265	$0.0019	$0.0019	$0.4170	$0.0019	$0.4151
(ITP)	$13.0110	$0.0019	$0.0019	$0.4297	$0.0019	$0.4278
(X-35)	$10.2027	$0.0019	$0.0019	$0.3373	$0.0019	$0.3354
X-39	$13.2089	$0.0019	$0.0019	$0.4362	$0.0019	$0.4343
Incremental Surcharges						
Hubline	$ 1.8607	$0.0000	$0.0000	$0.0000	$0.0000	$0.0612
Secondary 1/		$0.0612	$0.0000			
Tiverton	$ 1.6424	$0.0000	$0.0000	$0.0000	$0.0000	$0.0540
Ramapo	$ 7.5608	$0.0000	$0.0000	$0.2486	$0.0000	$0.2486

•RATE SCHEDULE AFT-1S

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-2/F-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-4)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0031	$0.0864
(STB/SS-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			

•OTHER FIRM RATE SCHEDULES

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
AFT-E	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0058		$0.0600		
AFT-4	$ 3.5211	$0.0032		$0.1190		
AFT-CL:						
Canal	$ 2.0858	$0.0019	$0.0019	$0.0705	$0.0019	$0.0686
Middletown	$ 3.2764	$0.0019	$0.0019	$0.1096	$0.0019	$0.1077
Cleary	$ 1.4529	$0.0019	$0.0019	$0.0497	$0.0019	$0.0478
Lake Road	$ 0.6476	$0.0019	$0.0019	$0.0232	$0.0019	$0.0213
Brayton Pt.	$ 1.2700	$0.0019	$0.0019	$0.0437	$0.0019	$0.0418
Manchester	$ 2.4500	$0.0019	$0.0019	$0.0824	$0.0019	$0.0805
Bellingham	$ 0.9714	$0.0019	$0.0019	$0.0338	$0.0019	$0.0319
Phelps Dodge	$ 0.0000	$0.0185	$0.0019	$0.0185	$0.0019	$0.0000
Cape Cod	$ 9.0501	$0.0019	$0.0019	$0.2994	$0.0019	$0.2975
Northeast Gateway	$ 4.3449	$0.0019	$0.0019	$0.1447	$0.0019	$0.1428
J-2 Facility	$ 4.9077	$0.0019	$0.0019	$0.1632	$0.0019	$0.1613
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun	
	Max	Min	Max	Min
AIT-1	$0.2440	$0.0095	$0.2440	$0.0095
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0437	$0.0019	$0.0437	$0.0019
Manchester	$0.0824	$0.0019	$0.0824	$0.0019
Canal	$0.0705	$0.0019	$0.0705	$0.0019
Cape Cod	$0.2994	$0.0019	$0.2994	$0.0019
Northeast Gateway	$0.1447	$0.0019	$0.1447	$0.0019
J-2 Facility	$0.1632	$0.0019	$0.1632	$0.0019
PAL	$0.2440	$0.0000	$0.0000	$0.0000

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charge of $0.0019.

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP

Rate Schedule FT-NN
Firm Transportation Service

	Base Tariff Rate 1/	ACA Adj.	Total Current Rate
	$/Dth		
Reservation Charge:			
Maximum	$1.6666		$\boxed{\$1.6666}$
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0019	$0.0019
Minimum	$0.0000	$0.0019	$0.0019
Authorized Overrun Commodity Charge:			
Maximum	$0.0548	$0.0019	$0.0567
Minimum	$0.0000	$0.0019	$0.0019
Fuel and Losses			
Percentage			0.5%
Volumetric Reservation Charge			
Maximum	$0.0548		$0.0548
Minimum	$0.0000		$0.0000

1/ The Base Tariff Rate is the effective rate on file with the Commission, excluding adjustment approved by the Commission.

Granite State Gas Transmission, Inc.
FERC Gas Tariff
Fourth Revised Volume No. 1

First R
Superseding
Original Sheet No. 16

Rate Schedule FT-NN
Firm Transportation Service

	Base Tariff Rate ($/Dth)	ACA Adj. ($/Dth)	Total Current Rate ($/Dth)
Reservation Charge:			
Maximum	$3.5518		$\boxed{\$3.5518}$
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0019	$0.0019
Minimum	$0.0000	$0.0019	$0.0019
Authorized Overrun Commodity Charge:			
Maximum	$0.1168	$0.0019	$0.1187
Minimum	$0.0000	$0.0019	$0.0019
Fuel and Losses Percentage			0.5%
Volumetric Reservation Charge			
Maximum	$0.1168	$0.0019	$0.1187
Minimum	$0.0000	$0.0019	$0.0019

Issued by: Mark H. Collin, Treasurer
Issued on: June 29, 2010

Effective: August 1,2010

Iroquois Gas Transmission System, L.P. Thirty First Revised Sheet No. 4
FERC Gas Tariff Superseding
FIRST REVISED VOLUME NO. 1 Thirtieth Revised Sheet No. 4

RATES (All in $ Per Dth)

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates ---- Applicable to Non-Eastchester/Non-Contesting Shippers 2/ ---- Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$\boxed{\$6.5971}$
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Jan 26, 2009 Effective: Jan 27, 2009

Portland Natural Gas Transmission System
FERC Gas Tariff
Second Revised Volume No. 1

Seventh Revised Sheet No. 100 : Effective
Supercedes Sixth Revised Sheet No. 100

Statement of Transportation Rates

(Rates per DTH)

Rate Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ Rate

FT Recourse Reservation Rate

-- Maximum $27.4017 --------- $27.4017

-- Minimum $00.0000 --------- $00.0000

Seasonal Recourse Reservation Rate

-- Maximum $52.0632 --------- $52.0632

-- Minimum $00.0000 --------- $00.0000

Recourse Usage Rate

-- Maximum $00.0000 $00.0019 $00.0019

-- Minimum $00.0000 $00.0019 $00.0019

FT-FLEX Recourse Reservation Rate

--Maximum $18.3920 ------- $18.3920

--Minimum $00.0000 ------- $00.0000

Recourse Usage Rate

--Maximum $00.2962 $00.0019 $00.2981

--Minimum $00.0000 $00.0019 $00.0019

Portland Natural Gas Transmission System
FERC Gas Tariff
Second Revised Volume No. 1

Eighth Rev
Superseding
Seventh Revised Sheet No. 100

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$40.2456	----------	$40.2456
	-- Minimum	$00.0000	----------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$76.4666	----------	$76.4666
	-- Minimum	$00.0000	----------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0019	$00.0019
	-- Minimum	$00.0000	$00.0019	$00.0019
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$27.0128	--------	$27.0128
	--Minimum	$00.0000	--------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.4350	$00.0019	$00.4369
	--Minimum	$00.0000	$00.0019	$00.0019

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

Minimum	down to -1.00%
Maximum	up to +1.00%

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 17 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

Issued by: David J. Haag - Manager, Rates and Regulatory Affairs
Issued on: May 12, 2010 Effective on: June 11, 2010

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

	DELIVERY ZONE							
RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

		DELIVERY ZONE							
	RECEIPT ZONE	0	L	1	2	3	4	5	6
PCB Adjustment: 1/	0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	L		$0.00						
	1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2 /

	DELIVERY ZONE							
RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-A Reservation Rate is $0.00 per Dth

Notes:
1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
2/ Maximum rates are inclusive of base rates and above surcharges.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	(PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/					
Segment U	$9.65		$0.00	$9.65	
Segment 1	$1.33		$0.00	$1.33	
Segment 2	$8.08		$0.00	$8.08	
Segment 3	$5.07		$0.00	$5.07	
Segment 4	$5.54		$0.00	$5.54	
Commodity Rate 2/, 3/					
Segments U, 1, 2, 3 & 4		$0.0019		$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/					
Segment U	$0.3173			$0.3173	5.52%
Segment 1	$0.0437			$0.0437	0.69%
Segment 2	$0.2656			$0.2656	0.59%
Segment 3	$0.1667			$0.1667	0.73%
Segment 4	$0.1821			$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 105.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

CURRENTLY EFFECTIVE RATES 2/01/2010

•RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.8120	6.5890	2.7250
WLA-AAB	2.8280	2.6050	1.1310
ELA-AAB	2.3750	2.1520	0.9500
ETX-AAB	2.1890	1.9660	0.8760
STX-STX	5.7400	5.5170	2.2950
STX-WLA	5.8990	5.6760	2.3580
STX-ELA	6.8160	6.5930	2.7240
STX-ETX	6.8170	6.5940	2.7250
WLA-WLA	2.0570	1.8340	0.8220
WLA-ELA	2.8310	2.6080	1.1310
WLA-ETX	2.8300	2.6070	1.1300
ELA-ELA	2.3790	2.1560	0.9500
ETX-ETX	2.1930	1.9700	0.8760
ETX-ELA	2.3780	2.1550	0.9500
M1-M1	4.5870	4.3640	1.8320
M1-M2	8.5650	8.3420	3.4230
M1-M3	11.2800	11.0570	4.5080
M2-M2	6.6330	6.4100	2.6510
M2-M3	9.4860	9.2630	3.7910
M3-M3	5.3710	5.1480	2.1460

7(C) RATE SCHEDULES	
FTS	5.3500
FTS-2	7.9590
FTS-4	7.7210
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0100

SCT DEMAND CHARGES	
Access Area	0.0020
M1-M1	0.0030
M1-M2	0.0030
M1-M3	0.0040

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0090	0.0098	0.0143	0.0143	0.0363	0.0726	0.0976
from WLA		0.0060	0.0105	0.0105	0.0325	0.0688	0.0938
from ELA			0.0089	0.0089	0.0309	0.0672	0.0922
from ETX				0.0089	0.0309	0.0672	0.0922
from M1					0.0220	0.0583	0.0833
from M2						0.0408	0.0655
from M3							0.0292

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0088						
from WLA	0.0096	0.0059					
from ELA	0.0140	0.0103	0.0087				
from ETX	0.0140	0.0103	0.0087	0.0087			
from M1	0.0358	0.0321	0.0305	0.0305	0.0218		
from M2	0.0720	0.0683	0.0667	0.0667	0.0580	0.0405	
from M3	0.0968	0.0931	0.0915	0.0915	0.0828	0.0651	0.0290

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1903	0.1963	0.2309	0.2309	0.3962	0.5632	0.6774
from WLA		0.0662	0.0961	0.0961	0.2614	0.4284	0.5427
from ELA			0.0797	0.0797	0.2449	0.4119	0.5262
from ETX				0.0736	0.2388	0.4058	0.5201
from M1					0.1653	0.3323	0.4465
from M2						0.2513	0.3698
from M3							0.1983

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1901						
from WLA	0.1961	0.0661					
from ELA	0.2306	0.0959	0.0795				
from ETX	0.2306	0.0959	0.0795	0.0734			
from M1	0.3957	0.2610	0.2445	0.2384	0.1651		
from M2	0.5626	0.4279	0.4114	0.4053	0.3320	0.2510	
from M3	0.6766	0.5420	0.5255	0.5194	0.4460	0.3694	0.1981

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1904	0.1964	0.2311	0.2311	0.3966	0.5636	0.6779
from WLA		0.0663	0.0962	0.0962	0.2618	0.4288	0.5431
from ELA			0.0798	0.0798	0.2453	0.4123	0.5266
from ETX				0.0736	0.2391	0.4061	0.5204
from M1					0.1655	0.3325	0.4468
from M2						0.2516	0.3701
from M3							0.1985

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1902						
from WLA	0.1962	0.0662					
from ELA	0.2308	0.0960	0.0796				
from ETX	0.2308	0.0960	0.0796	0.0734			
from M1	0.3961	0.2614	0.2449	0.2387	0.1653		
from M2	0.5630	0.4283	0.4118	0.4056	0.3322	0.2513	
from M3	0.6771	0.5424	0.5259	0.5197	0.4463	0.3697	0.1983

TransCanada
In business to deliver

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	$\boxed{0.78572}$	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	$\boxed{1.96558}$	0.03798	0.10260

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Dawn	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn	Iroquois	10.82669	0.01413	0.3700	0.4070
8	Union Dawn	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn	East Hereford	16.76744	0.02275	0.5741	0.6315
12	Union Dawn	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

1. Replacement Shipper's Name: Northern Utilities, Inc.

2. a. Master Service Agreement for Capacity Release Agreement No.: CRT-NUI-0079
   b. Underlying Rate Schedule No.: FT-1

3. Replacement Shipper's Firm Transportation Agreement No.: **CRL-NUI-0725**
   Temporary Assignment of Canadian portion Agreement No.: **CRL-NUI-C0725**

4. Releasing Shipper's Firm Transportation Agreement No.: FT1-DTE-0425

5. Commencement Date: **04/01/2008**
   Termination Date: **10/31/2017**

6. Reservation Quantity: **17,172 Dth/d**

7. Primary Receipt Point(s): — Maximum Daily Reservation Quantity Dth

   Alliance Interconnect — **17,172**

8. Primary Delivery Point(s): — Maximum Daily Reservation Quantity Dth

   St. Clair (US) Interconnect — **17,172**

9. Reservation Rate: $7.6042/Dth ($0.2500 per Dth on a 100% load factor basis), exclusive of ACA and fuel reimbursement.

10. Usage Rate: $0.00/Dth

11. Special Terms and Conditions of Release (if any):

    Replacement shipper will receive corresponding Vector-Canada capacity from St. Clair (International Border) to Dawn at no additional cost.

    The Term of the FT1-DTE-0425 contract underlying this release is subject to the June 30, 2005 Precedent Agreement between DTE Energy Trading, Inc. and Vector Pipeline L.P.

Authorized Signature of Replacement Shipper: DTe

Name: DON TUCHINSKY

Title: ANALYST

Telephone: (508) 836-7259

Fax: ( ) 508-870-2294

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

1. Replacement Shipper's Name: Northern Utilities, Inc.

2. a. Master Service Agreement for Capacity Release Agreement No.: CRT-NUI-0079
   b. Underlying Rate Schedule No.: FT-1

3. Replacement Shipper's Firm Transportation Agreement No.: **CRL-NUI-0727**
   Temporary Assignment of Canadian portion Agreement No.: **CRL-NUI-C0727**

4. Releasing Shipper's Firm Transportation Agreement No.: FT1-DTE-0426

5. Commencement Date: **11/01/2008** Winter Only (November 1 thru March 31 on an annual basis)
   Termination Date: **03/31/2017**

6. Reservation Quantity: **17,086 Dth/d**

7. Primary Receipt Point(s): Maximum Daily Reservation Quantity Dth

   Washington 10 Interconnect **17,086**

8. Primary Delivery Point(s): Maximum Daily Reservation Quantity Dth

   St. Clair (US) Interconnect **17,086**

9. Reservation Rate: $\boxed{\$4.5625/\text{Dth}}$ ($0.1500 per Dth on a 100% load factor basis), exclusive of ACA and fuel reimbursement.

10. Usage Rate: $0.00/Dth

11. Special Terms and Conditions of Release (if any):

    Replacement shipper will receive corresponding Vector-Canada capacity from St. Clair (International Border) to Dawn at no additional cost.

    The Term of the FT1-DTE-0425 contract underlying this release is subject to the June 30, 2005 Precedent Agreement between DTE Energy Trading, Inc. and Vector Pipeline L.P.

Authorized Signature of Replacement Shipper: DTC

Name: DON TULCHINSKY

Title: ANALYST

Telephone: ( ) 508-836 7257

Fax: ( ) 508-870-2294

INFORMATIONAL POSTINGS

Capacity
Gas Quality
Index of Customers
Notices
Posted Imbalances
Standards of Conduct
Tariff
Title Sheet
Table of Contents
Preliminary Statement
Map
Currently Effective Rates
Rate Schedules
General Terms and Conditions
Form of Service Agreement
Entire Tariff
Sheet Index
Vector - Canada Tariff
Transactional Reporting
Other
Downloads
Search
Customer Activities
Site Map

Previous Next

Vector Pipeline L.P.
FERC Gas Tariff
Original Volume No. 1

Eleventh Revised Sheet No. 20
Superseding
Tenth Revised Sheet No. 20

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.2501	0.0000	$\boxed{\$7.7745}$	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0019	0.0019	0.0019	0.0019
Usage and ACA Charge	0.0019	0.0019	0.0019	0.0019

Negotiated Rates:

The effective maximum negotiated charge for any negotiated rate transportation agreement is the charge agreed to by the parties, as set forth in the attached Tariff sheets.

Rate Schedule FT-L 1/

Recourse Rates:

34

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum

Exhibit A
To
Firm Transportation Agreement No. FT1-NUI-0122
Under Rate Schedule FT-1
Between
Vector Pipeline L.P. and Northern Utilities, Inc.

Primary Term	05/01/2006 - 03/31/2016
Contracted Capacity:	6,070 Dth/day
Primary Receipt Points:	Alliance Interconnect
Primary Delivery Points:	St. Clair (US) Interconnect
Rate Election Recourse:	

The Reservation Charge applicable to this service is $\boxed{\text{\$8.0908/Dth/month}}$ ($0.2660 per Dth on a 100% load factor basis), exclusive of fuel reimbursement, Annual Charge Adjustment ("ACA") and any other future surcharges. Secondary points within the primary path and out of path secondary backhauls are subject to the same rate as the primary path.

**Exhibit A
To
FT-1 Firm Transportation Agreement No. FT1-NUI-C0122
Under Toll Schedule FT-1
Between
Vector Pipeline Limited Partnership and Northern Utilities, Inc.**

Primary Term:	05/01/2006 – 03/31/2016
Contracted Capacity:	6,404 GJ/d
Primary Receipt Points:	St. Clair (Canada) Interconnect
Primary Delivery Points:	Dawn Interconnect

Toll Election Negotiated:
The Reservation Charge applicable to this service is $0.4623/GJ/month ($0.0152 per GJ on a 100% load factor basis). Secondary points within the primary path and out of secondary from Dawn Interconnect to St. Clair (Canada) Interconnect are subject to the same rate as the primary path.

Bank of Canada

SEE ALSO:

[10-Year Currency Converter]

FREQUENTLY ASKED:

Why is the currency I'm looking for not listed here?

The Bank currently collects data for over 50 foreign currencies. These data are intended primarily for individuals with a research interest in foreign exchange markets and represent only a sampling of currencies.

More comprehensive currency converters include CanadianForex and OANDA.com.

Are the exchange rates shown here accepted by the Canada Revenue Agency?

Yes. The Agency accepts Bank of Canada exchange rates as the basis for calculations involving income and expenses that are denominated in foreign currencies.

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:

10-Year Currency Converter

Using rates for: 20 Jul 2010

Convert to and from Canadian dollars, using the latest noon rates.

Currency:	U.S. dollar
Amount:	1.00
Convert:	(•) **from $Can** ( ) **to $Can**
Use the:	(•) Nominal rate HELP ( ) Cash rate (4%) HELP
Answer:	0.95 CONVERT
Exchange rate:	0.9500

Summary:

On 20 Jul 2010, 1.00 Canadian dollar(s) = 0.95 U.S. dollar(s), at an exchange rate of 0.9500 (using nominal rate.)

Effective 1 January 2009, the euro replaces the Slovak koruna.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA					
Deliverability Rate	$2.02		$0.00	$2.02	
Space Rate	$0.0248		$0.0000	$0.0248	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	
Overrun Rate	$0.2427			$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA					
Deliverability Rate	$1.15		$0.00	$1.15	
Space Rate	$0.0185		$0.0000	$0.0185	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
Overrun Rate	$0.1380			$0.1380	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

•OTHER TRANSPORTATION SERVICES

	Reservation	Usage-1	Shrinkage	
			In Path	Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3400 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	$\boxed{0.6600}$		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	5.4934		0.36%	
FT-1/NC	6.5590		0.00%	
FT-1/RIV	10.4380		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	1.2690 2/		0.00%	
FT-1/TME	12.3400		4.01%	4.25%
FT-1/TME2	24.4038		3.69%	4.63%
MLS-1/FH	0.6315		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270		0.01%	

1/ Pursuant to Section 26 of the General Terms and Conditions
2/ Effective May 1 through September 30
3/ Per Section 3.3 of MLS-1 Rate Schedule

•STORAGE SERVICES

	RES.	SPACE	INJ.	WITH.
SS	5.5050	0.1293	0.0339	0.0592
SS-1	$\boxed{5.6020}$	$\boxed{0.1293}$	0.0339	0.0591
X-28	4.9060	0.1293	0.0339	0.0549
FSS-1	$\boxed{0.8950}$	$\boxed{0.1293}$	0.0339	0.0339
ISS-1		0.0323	0.1896	0.0339

•SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.12%	2.32%	3.38%	3.38%	5.35%	7.30%	8.59%
from WLA	1.40%	1.40%	2.48%	2.48%	4.45%	6.40%	7.69%
from ELA	2.08%	2.08%	2.08%	2.08%	4.05%	6.00%	7.29%
from ETX	2.12%	2.08%	2.08%	2.08%	4.05%	6.00%	7.29%
from M1					1.97%	3.92%	5.21%
from M2						2.99%	4.30%
from M3							2.36%

April 1 through November 30

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.06%	2.22%	3.02%	3.02%	4.97%	6.46%	7.46%
from WLA	1.52%	1.52%	2.34%	2.34%	4.29%	5.78%	6.78%
from ELA	2.03%	2.03%	2.03%	2.03%	3.98%	5.47%	6.47%
from ETX	2.06%	2.03%	2.03%	2.03%	3.98%	5.47%	6.47%
from M1					1.95%	3.44%	4.44%
from M2						2.72%	3.73%
from M3							2.25%

NON-ASA RATE SCHEDULES

FTS-4 LEIDY		**FTS**	1.29%
(Apr 1-Nov 14)	1.00%	**FTS-2**	0.00%
(Nov 15-Mar 31)	4.89%	**X-127**	0.00%
FTS-4 CHMSBG	0.00%	**X-129**	0.00%
FTS-5	0.00%	**X-130**	0.00%
FTS-7 M3	2.00%	**X-135**	0.00%
FTS-7 M1 & M2	0.00%	**X-137**	1.30%
FTS-8 M3	1.50%		
FTS-8 M1 & M2	0.00%		

ASA STORAGE RATE SCHEDULES

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	3.11%	3.04%
FSS-1,ISS-1	0.96%	0.96%
INJECTIONS	0.96%	0.96%
INVENTORY LEVEL	0.08%	0.08%

•SURCHARGES

ACA Surcharge
Commodity 0.0019

•The Summary of Rates serves as a handy reference and does not replace Texas Eastern's Tariff.

Attention: Vice-President, Washington 10 Storage Corporation
Telephone: (313) 235-6445
Fax: (313) 235-6450

SHIPPER:

NORTHERN UTILITIES, INC.
300 Friberg Parkway
Westborough, MA 01581-5039

INVOICES, STATEMENTS AND NOMINATIONS

Stacy Djucik
1500 – 165th Street
Hammond, IN 46324
Telephone: (219) 853-4320

ALL OTHER MATTERS

F. Chico DaFonte
Telephone: (508) 836-7253
Facsimile: (508) 870-2294
Email: fdafonte@nisource.com

ARTICLE VIII: FURTHER AGREEMENT

Article II is amended to add the following sentence at the end of the first paragraph:

The Monthly Deliverability Rate and Monthly Capacity Rate shall be paid in the form of a monthly demand charge of $240,833.34 (assuming a typical 12 month, April through March storage cycle). The parties agree that Transporter may, from time to time, modify the Monthly Deliverability Rate and the Monthly Capacity Rate set forth in Exhibit I, so long as the amounts set forth on the revised Exhibit I do not exceed Shipper's monthly demand charge of $240,833.34. Unless otherwise specified, the revised Exhibit I will be effective the first day of the month immediately following the date that Transporter provides a copy of the revised Exhibit I to Shipper.

Northern Utilities, Inc. Projected Peaking Supply 1 Demand Rate (Unit Call Payment) Effective November 2010 through October 2011		
PPI_Base	127.17	Average PPI - Nov 95 through Oct 96
Projected PPI	181.85	Average PPI - Nov 09 through Oct 10
Base Unit Call Payment	$ 30.83	NUI Agreement with Distrigas
Projected Unit Call Payment	$ 44.09	Base UCP times (PPI / PPI_BASE)

Charge and the corresponding Base or Augmented Service SCQ and shall be payable in 5 equal monthly installments during the Winter Season of each Contract Year in accordance with the terms of Article 10.

Contract Year	Base Service Demand Charge ($/MMBtu)	Augmented Service Demand Charge ($/MMBtu)
2001-02	1.90	1.60
2002-03	1.90	1.45
2003-04	1.65	1.45
2004-05	1.65	1.35
2005-06	1.45	1.35
2006-07	1.40	1.35
2007-08	1.40	1.35
2008-09	1.40	1.35
2009-10	1.35	1.35
2010-11	1.35	1.35

7.2 <u>Commodity Charge</u>: Buyer shall pay Seller a Commodity Charge for each MMBtu requested and delivered during any Month under either the Base or Augmented Service, as appropriate, equal to the average of the prices posted in *Gas Daily's "Daily Price Survey"* for deliveries to the Tenn Zone 6 (delivered) and Algonquin City-gates on the actual delivery date plus $0.60 per MMBtu. If one or both City-gate prices from *"Daily Price Survey"* is unavailable for such date, then the average of the prices for deliveries to the Tenn Zone 6 (delivered) and Algonquin City-gates from the *"Daily Price Survey"* for the next Business Day shall apply. If *Gas Daily* is no longer published or if it no longer publishes in the *"Daily Price Survey,"* either or both prices for deliveries to the Tenn Zone 6 (delivered) and Algonquin City-gates, a comparable replacement publication and/or index mutually and reasonably agreeable to the Parties shall be used. In the event the Parties are unable to reach agreement regarding a comparable publication or index to be utilized, either Party may elect to resolve the dispute by arbitration under Article XIV by giving written notice to the other Party In the event either Party elects to resolve the dispute by arbitration, the dispute shall be resolved by arbitration regardless of the amount in controversy The

Northern Utilities, Inc.
Retail Marketer Capacity Assignment Revenue Projections
November 2010 through October 2011

Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (2,094,795)	Page 2
NH Division Storage Contract Capacity Assignment	$ (216,339)	Page 3
NH Division Peaking Demand	$ (392,804)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 71,945	Page 5
NH Division Net PNGTS Litigation Costs & Projected 2008 Rate Case Refund Assigned to Retail Suppliers	$ 31,856	Page 6
NH Division Capacity Assignment Demand Revenue	$ (2,600,137)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2010 through October 31, 2011

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	NH Annual Cap Assign Credit
Algonquin	93201A1C	$ 14,417	$ 6,097	$ -	N	NA	NA	-	-	$ -
Algonquin	93201A1C	$ 69,215	$ -	$ -	N	NA	NA	-	-	$ -
Algonquin	93002F	$ 308,943	$ -	$ -	Y	4,211	-	(267)	-	$ (19,589)
Granite	10-010-FT-NN	$ 79,650	$ 118,245	$ 135,425	Y	23,896	35,475	(1,516)	(2,553)	$ (21,982)
Granite	10-010-FT-NN	$ 848,738	$ 1,260,001	$ 1,443,061	Y	23,896	35,475	(1,516)	(2,553)	$ (234,241)
Iroquois	R181001	$ 520,036	$ -	$ -	Y	6,569	-	(417)	-	$ (33,012)
PNGTS	1997-003	$ 30,142	$ -	$ -	Y	1,100	-	(70)	-	$ (1,918)
PNGTS	1997-003	$ 486,972	$ -	$ -	Y	1,100	-	(70)	-	$ (30,989)
PNGTS	1997-004	$ -	$ 1,718,086	$ -	Y	-	33,000	-	(2,375)	$ (123,650)
PNGTS	1997-004	$ -	$ 10,093,591	$ -	Y	-	33,000	-	(2,375)	$ (726,433)
Tennessee	5083	$ 916,763	$ -	$ -	Y	4,605	-	(292)	-	$ (58,131)
Tennessee	5083	$ 1,554,390	$ -	$ -	Y	8,550	-	(542)	-	$ (98,536)
Tennessee	5265	$ -	$ 187,514	$ -	Y	-	2,653	-	(191)	$ (13,500)
Tennessee	5292	$ 83,179	$ -	$ -	Y	1,406	-	(89)	-	$ (5,265)
Tennessee	39735	$ 54,960	$ -	$ -	Y	929	-	(59)	-	$ (3,490)
Tennessee	41099	$ 252,436	$ -	$ -	Y	4,267	-	(271)	-	$ (16,032)
Tennessee	46314	$ 56,202	$ -	$ -	Y	950	-	(60)	-	$ (3,550)
Tennessee	31861	$ 84,081	$ -	$ -	Y	1,382	-	(88)	-	$ (5,354)
Tennessee	31861	$ 107,458	$ -	$ -	Y	844	-	(54)	-	$ (6,875)
Texas Eastern	800384	$ 67,257	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800436	$ 4,125	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 941	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 236	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 1,308	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 611	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 7,986	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	29594	$ 829,238	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	33322	$ -	$ 7,660,696	$ -	Y	-	35,872	-	(2,582)	$ (551,403)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	$ -	Y	-	17,172	-	(1,236)	$ (112,785)
Vector	CRL-NUI-0727	$ -	$ 389,774	$ -	Y	-	17,086	-	(1,230)	$ (28,059)
Vector	FT-1-NUI-0122	$ 566,295	$ -	$ -	N	NA	NA	-	-	$ -
Vector	FT-1-NUI-C0122	$ 33,750	$ -	$ -	N	NA	NA	-	-	$ -

Total NH Capacity Assignment Credits	$ (2,094,795)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 1, 2010 through October 31, 2011

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Storage Assigned NH	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 116,126	Y	N	7.20%	(18,663)	(305)	$ (8,357)
W-10	01052	$ 2,890,000	Y	Y	7.20%	(244,685)	(2,447)	$ (207,982)

Total NH Division Storage Capacity Assignment $ (216,339)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2009 through October 2010

Asset Management Agreeement Revenue					
Resources	Projected Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	$ (442,000)	No	Pipeline	6.34%	$ -
Wash 10 via Vector, TCPL, PNGTS	$ (1,100,000)	Yes	Pipeline	6.34%	$ 69,786
PNGTS Contract 1997-003	$ (30,000)	Yes	Storage	7.20%	$ 2,159
Tennessee Niagara	$ (100,000)	No	Pipeline	6.34%	$ -
Tennessee Long-Haul	$ (835,000)	No	Pipeline	6.34%	$ -
Total Asset Management	$ (2,507,000)				$ 71,945

Capacity Release Revenue					
Resources	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Texas Eastern Contract 800384	$ (66,701)	No	Pipeline	6.34%	$ -
AGT Contract 93201A1C	$ (98,779)	No	Pipeline	6.34%	$ -
Tennessee 5265	$ (259,050)	No	Pipeline	7.20%	$ -
Total Capacity Release	$ (424,530)				$ -

Total Asset Management and Capacity Release Revenue	$ (2,931,530)	$ 71,945

Northern Utilities, Inc.
New Hampshire Division
Peaking Demand Capacity Assignment Revenues
November 2010 through April 2011

Month	Retail Supplier 1	Retail Supplier 2	Retail Supplier 3	Retail Supplier 4	Retail Supplier 5	Retail Supplier 6	Total Peaking Demand TCQ	Rate	Demand Revenue
Nov-10	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Dec-10	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Jan-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Feb-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Mar-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Apr-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)

Total Division Peaking Demand Revenue $ (392,804)

Northern Utilities, Inc.
New Hampshire Division
PNGTS Litigation Costs & Projected 2008 Rate Case Refund - Assigned to Retail Suppliers
November 2010 through October 2011

PNGTS Litigation Costs	$ 183,943
PNGTS Projected 2008 Rate Case Refund	$ (628,298)
Net PNGTS Litigation Items	$ (444,355)

PNGTS Contract	MDQ	Percentage MDQ	Allocated PNGTS Litigation Items	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ (14,334)	Pipeline	6.34%	$ 909
PNGTS Contract 1997-004	33,000	97%	$ (430,021)	Storage	7.20%	$ 30,947
PNGTS Total	34,100	100%	$ (444,355)			$ 31,856

Estimate of PNGTS Transportation Costs Subject to Refund

	Prior Rates: Annual Rate	Prior Rates: Winter Rate	Filed Rates: Annual Rate	Filed Rates: Winter Rate	Subject to Refund: Annual Rate	Subject to Refund: Winter Rate
Prior Rate	$ 25.245	$ 48.515	$ 27.4017	$ 52.063	$ 2.157	$ 3.549
Volume	1,100	33,000	1,100	33,000	1,100	33,000

Month	Prior Rates FT-1997-003	Prior Rates FT-1997-004	Prior Rates Total Cost	Filed Rates FT-1997-003	Filed Rates FT-1997-004	Filed Rates Total Cost	Subject to Refund FT-1997-003	Subject to Refund FT-1997-004	Subject to Refund Total Cost
Sep-08	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Oct-08	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Nov-08	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Dec-08	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Jan-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Feb-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Mar-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Apr-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
May-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jun-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jul-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Aug-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Sep-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Oct-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Nov-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Dec-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Jan-10	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Feb-10	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Mar-10	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Apr-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
May-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jun-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jul-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Aug-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Sep-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Oct-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Period Total	$ 722,007	$ 16,009,851	$ 16,731,858	$ 783,689	$ 17,180,856	$ 17,964,545	$ 61,682	$ 1,171,005	$ 1,232,687

Month	ME Allocator	NH Allocator	ME Refund	NH Refund	Begin Month Balance	End Month Balance	Average Balance	Interest Rate	Interest
Sep-08	49.93%	50.07%	$ 1,185	$ 1,188	$ -	$ 2,372	$ 1,186	5.30%	$ 5
Oct-08	49.93%	50.07%	$ 1,185	$ 1,188	$ 2,378	$ 4,750	$ 3,564	5.00%	$ 15
Nov-08	49.91%	50.09%	$ 59,629	$ 59,844	$ 4,765	$ 124,238	$ 64,502	5.00%	$ 269
Dec-08	49.91%	50.09%	$ 59,629	$ 59,844	$ 124,507	$ 243,980	$ 184,243	5.00%	$ 793
Jan-09	49.91%	50.09%	$ 59,629	$ 59,844	$ 244,773	$ 364,246	$ 304,510	4.52%	$ 1,185
Feb-09	49.91%	50.09%	$ 59,629	$ 59,844	$ 365,431	$ 484,904	$ 425,168	4.52%	$ 1,495
Mar-09	49.91%	50.09%	$ 59,629	$ 59,844	$ 486,399	$ 605,872	$ 546,135	4.52%	$ 2,126
Apr-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 607,997	$ 610,370	$ 609,183	3.37%	$ 1,711
May-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 612,080	$ 614,453	$ 613,267	3.37%	$ 1,780
Jun-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 616,233	$ 618,605	$ 617,419	3.37%	$ 1,734
Jul-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 620,339	$ 622,711	$ 621,525	3.25%	$ 1,739
Aug-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 624,451	$ 626,823	$ 625,637	3.25%	$ 1,751
Sep-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 628,574	$ 630,946	$ 629,760	3.25%	$ 1,706
Oct-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 632,652	$ 635,024	$ 633,838	3.25%	$ 1,774
Nov-09	52.54%	47.46%	$ 62,771	$ 56,702	$ 636,798	$ 756,271	$ 696,534	3.25%	$ 1,886
Dec-09	52.54%	47.46%	$ 62,771	$ 56,702	$ 758,157	$ 877,630	$ 817,894	3.25%	$ 2,289
Jan-10	52.54%	47.46%	$ 62,771	$ 56,702	$ 879,919	$ 999,392	$ 939,656	3.25%	$ 2,630
Feb-10	52.54%	47.46%	$ 62,771	$ 56,702	$ 1,002,022	$ 1,121,495	$ 1,061,758	3.25%	$ 2,684
Mar-10	52.54%	47.46%	$ 62,771	$ 56,702	$ 1,124,179	$ 1,243,651	$ 1,183,915	3.25%	$ 3,313
Apr-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,246,965	$ 1,249,337	$ 1,248,151	3.25%	$ 3,380
May-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,252,718	$ 1,255,090	$ 1,253,904	3.25%	$ 3,509
Jun-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,258,599	$ 1,260,971	$ 1,259,785	3.25%	$ 3,412
Jul-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,264,383	$ 1,266,756	$ 1,265,570	3.25%	$ 3,542
Aug-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,270,298	$ 1,272,670	$ 1,271,484	3.25%	$ 3,558
Sep-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,276,228	$ 1,278,601	$ 1,277,415	3.25%	$ 3,460
Oct-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,282,060	$ 1,284,433	$ 1,283,247	3.25%	$ 3,591
Period Total	51.22%	48.78%	$ 631,382	$ 601,304	$ 1,288,024				$ 55,337
Period Total Including Interest			$ 659,726	**$ 628,298**				51.22% ME	$ 28,344
								48.78% NH	$ 26,994

Northern Utilities, Inc.
Expenses Incurred to Oppose Proposed PNGTS Rate Increases, 9/1/2009 - 8/13/2010

Service Provider	Service Period	Description of Services	Date Paid	Expense	Rate Case
Bates White, LLC - Total RP08-306				$ 39,237.49	RP08-306
Benjamin Schlesinger and Associates, Inc. - Total RP08-306				$ 11,836.80	RP08-306
Benjamin Schlesinger and Associates, Inc. - Total RP10-729				$ 746.70	RP10-729
Continental Economics, Inc. - Total RP10-729				$ 4,560.00	RP10-729
Hall Estill Attorneys at Law - Total RP08-306				$ 273,630.42	RP08-306
Hall Estill Attorneys at Law - Total RP10-729				$ 42,549.91	RP10-729
Jeffry L. Fink - Total RP08-306				$ 1,862.00	RP08-306
Jeffry L. Fink - Total RP10-729				$ 2,416.80	RP10-729
Snake Hill Energy Resources, Inc. - Total				$ -	
Subtotal - Rate Case = RP08-306				$ 326,566.71	RP08-306
Subtotal - Rate Case = RP10-729				$ 50,273.41	RP10-729
Total Expenses Paid Since September 1, 2009				$ 331,126.71	

	Fixed PR Allocators	RP08-306	RP10-729	Since 9/1/09
Maine	51.1880%	$ 167,163.10	$ 25,733.97	$ 192,897.08
New Hampshire	48.8120%	$ 159,403.61	$ 24,539.44	**$ 183,943.04**
Total Expenses Paid Since September 1, 2009		$ 326,566.71	$ 50,273.41	$ 376,840.12

	RP08-306	RP10-729	ME Total
ME Division - Presented to MPUC in Aug 2009	$ 228,066.64		$ 228,066.64
ME Division - Expenses since September 1, 2009	$ 167,163.10	$ 25,733.97	$ 192,897.08
Total ME Division Expenses	$ 395,229.75	$ 25,733.97	$ 420,963.72

Schedule 6

Northern Utilities, Inc.

Northern Utilities, Inc.
Commodity Cost by Supply Source
May 2011 through October 2011

Description	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Season
Pipeline							
Chicago	$ 903,120	$ 833,067	$ 715,227	$ 669,633	$ 794,594	$ 939,516	$ 4,855,157
PNGTS	$ 161,281	$ 84,671	$ -	$ 164,762	$ 159,601	$ 166,455	$ 736,769
Niagara	$ 16,114	$ 43,516	$ -	$ 46,181	$ 144,112	$ 438,190	$ 688,111
Tennessee Production	$ 469,405	$ -	$ -	$ 30,609	$ 21,619	$ 293,181	$ 814,815
Storage							
Tennessee Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10 Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 46,100
Total Commodity Cost	$1,557,039	$ 968,424	$ 722,908	$ 919,110	$1,127,798	$1,845,675	$ 7,140,953

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) May 2011 through October 2011							
Description	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Season
Pipeline							
Chicago	177,969	163,742	139,235	129,731	153,671	179,215	943,562
PNGTS	31,826	16,603	0	31,826	30,800	31,826	142,882
Niagara	3,133	8,493	0	8,872	27,661	83,287	131,446
Tennessee Production	91,315	0	0	5,860	4,135	55,521	156,831
Storage							
Tennessee Storage	0	0	0	0	0	0	0
Washington 10 Storage	0	0	0	0	0	0	0
Peaking							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
LNG	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Total Delivered (Dth)	305,639	190,188	140,630	177,684	217,616	351,244	1,383,001

Northern Utilities, Inc.
Delivered Cost per Dth by Supply Source
May 2011 through October 2011

Description	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Season
Pipeline							
Chicago	$ 5.0746	$ 5.0877	$ 5.1368	$ 5.1617	$ 5.1708	$ 5.2424	$ 5.1456
PNGTS	$ 5.0675	$ 5.0996		$ 5.1769	$ 5.1819	$ 5.2301	$ 5.1565
Niagara	$ 5.1426	$ 5.1237		$ 5.2055	$ 5.2099	$ 5.2612	$ 5.2349
Tennessee Production	$ 5.1405			$ 5.2236	$ 5.2289	$ 5.2805	$ 5.1955
Storage							
Tennessee Storage							
Washington 10 Storage							
Peaking							
Peaking Supply 1							
Peaking Supply 2							
LNG	$ 5.1039	$ 5.3112	$ 5.5061	$ 5.6808	$ 5.8310	$ 5.9734	$ 5.5677
Total System	$ 5.0944	$ 5.0919	$ 5.1405	$ 5.1727	$ 5.1825	$ 5.2547	$ 5.1634

Northern Utilities, Inc. Commodity Cost by Supply Source November 2011 through April 2012							
Description	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Season
Pipeline							
Chicago	$ 816,356	$ 3,341	$ 148,303	$ 238,874	$ 536,585	$ 894,139	$ 2,637,598
PNGTS	$ -	$ -	$ -	$ 29,542	$ 66,801	$ 162,630	$ 258,974
Niagara	$ 460,334	$ 20,781	$ 212,999	$ 161,232	$ 389,603	$ 480,667	$ 1,725,616
Tennessee Production	$1,787,855	$1,920,783	$1,714,627	$1,824,360	$1,789,339	$1,020,270	$ 10,057,235
Storage							
Tennessee Storage	$ 98,126	$ 101,210	$ 356,087	$ 227,918	$ 260,217	$ -	$ 1,043,559
Washington 10 Storage	$ 170,796	$3,094,521	$4,227,551	$3,291,795	$2,263,502	$ 739,602	$ 13,787,767
Peaking							
Peaking Supply 1	$ -	$ -	$ -	$ 66,737	$ 157,449	$ -	$ 224,186
Peaking Supply 2	$ -	$ -	$ -	$ -	$ 60,386	$ -	$ 60,386
LNG	$ 8,249	$ 8,524	$ 8,524	$ 12,104	$ 81,341	$ 9,557	$ 128,300
Total Commodity Cost	$3,341,717	$5,149,161	$6,668,091	$5,852,564	$5,605,223	$3,306,865	$ 29,923,620

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) November 2011 through April 2012							
Description	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Season
Pipeline							
Chicago	141,230	559	24,142	39,141	89,750	168,837	463,659
PNGTS	0	0	0	4,527	10,411	30,800	45,738
Niagara	81,322	3,544	35,551	27,107	66,765	90,476	304,766
Tennessee Production	324,832	335,660	292,861	313,956	314,405	191,260	1,772,974
Storage							
Tennessee Storage	18,462	19,042	66,996	42,882	48,959	0	196,342
Washington 10 Storage	33,669	610,022	833,375	648,910	446,203	146,234	2,718,413
Peaking							
Peaking Supply 1	0	0	0	10,224	24,531	0	34,755
Peaking Supply 2	0	0	0	0	7,526	0	7,526
LNG	1,350	1,395	1,395	1,981	12,020	1,350	19,491
Total Delivered (Dth)	600,865	970,222	1,254,320	1,088,728	1,020,571	628,957	5,563,663

Northern Utilities, Inc.
Delivered Cost per Dth by Supply Source
November 2011 through April 2012

Description	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Season
Pipeline							
Chicago	$ 5.7803	$ 5.9752	$ 6.1430	$ 6.1030	$ 5.9786	$ 5.2959	$ 5.6887
PNGTS				$ 6.5256	$ 6.4162	$ 5.2803	$ 5.6621
Niagara	$ 5.6607	$ 5.8636	$ 5.9913	$ 5.9479	$ 5.8354	$ 5.3126	$ 5.6621
Tennessee Production	$ 5.5039	$ 5.7224	$ 5.8548	$ 5.8109	$ 5.6912	$ 5.3345	$ 5.6725
Storage							
Tennessee Storage	$ 5.3150	$ 5.3150	$ 5.3150	$ 5.3150	$ 5.3150		$ 5.3150
Washington 10 Storage	$ 5.0728	$ 5.0728	$ 5.0728	$ 5.0728	$ 5.0728	$ 5.0577	$ 5.0720
Peaking							
Peaking Supply 1				$ 6.5277	$ 6.4184		$ 6.4505
Peaking Supply 2					$ 8.0240		$ 8.0240
LNG	$ 6.1106	$ 6.1106	$ 6.1106	$ 6.1106	$ 6.7671	$ 7.0790	$ 6.5825
Total System	$ 5.5615	$ 5.3072	$ 5.3161	$ 5.3756	$ 5.4922	$ 5.2577	$ 5.3784

Source of Supply: Chicago (Interconnect of Alliance and Vector Pipelines)
Delivered to Northern via Vector, Union, TransCanada, Iroquois, Tennessee and Granite Pipelines
Delivered to Northern via Vector, Union, TransCanada, Iroquois, Tennessee, Algonquin Pipelines and Bay State Exchange Agreement

Line	City Gate Delivered Costs	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Purchased Volumes	Line 9	187,239	172,387	146,429	136,397	161,683	189,326	993,461
3	City Gate Delivered Volume	Sum Lines 65, 85 and 105	177,969	163,742	139,235	129,731	153,671	179,215	943,562
4	Total Purchase Cost	Line 14	$ 890,698	$ 825,562	$ 708,862	$ 663,709	$ 787,556	$ 931,295	$ 4,807,682
5	Variable Transportation Costs	Sum Lines 27, 47, 57, 67, 77, 87, 97 and 107	$ 12,422	$ 7,505	$ 6,365	$ 5,924	$ 7,038	$ 8,221	$ 47,475
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 903,120	$ 833,067	$ 715,227	$ 669,633	$ 794,594	$ 939,516	$ 4,855,157
7	Average Delivered Price	Line 5 divided by Line 2	$ 5.075	$ 5.088	$ 5.137	$ 5.162	$ 5.171	$ 5.242	$ 5.146
8									
9	Chicago Supply Costs								
10	Purchased Volumes	Sendout Optimization	187,239	172,387	146,429	136,397	161,683	189,326	993,461
11	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.707	$ 4.739	$ 4.791	$ 4.816	$ 4.821	$ 4.869	$ 4.789
12	NYMEX Cost	Line 9 times Line 10	$ 881,336	$ 816,943	$ 701,541	$ 656,889	$ 779,472	$ 921,829	$ 4,758,009
13	NYMEX Basis Price	FXW-7A, Line 3 of Page 1	$ 0.050	$ 0.050	$ 0.050	$ 0.050	$ 0.050	$ 0.050	$ 0.050
14	NYMEX Basis Costs	Line 9 times Line 12	$ 9,362	$ 8,619	$ 7,321	$ 6,820	$ 8,084	$ 9,466	$ 49,673
15	Total Purchase Price	Line 10 plus Line 12	$ 4.757	$ 4.789	$ 4.841	$ 4.866	$ 4.871	$ 4.919	$ 4.839
16	Total Purchase Cost	Line 11 plus Line 13	$ 890,698	$ 825,562	$ 708,862	$ 663,709	$ 787,556	$ 931,295	$ 4,807,682
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1&2								
20	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
21	Receipt Point: Alliance								
22	Delivery Point: Dawn (Interconnects with Union)								
23	Received Volume	Line 9	187,239	172,387	146,429	136,397	161,683	189,326	993,461
24	Fuel Loss Rate	FXW 7A, Line 36 of Page 2	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%
25	Delivered Volume	Line 22 times (1 - Line 23)	185,386	170,681	144,979	135,047	160,082	187,452	983,626
26	Variable Transportation Rate	FXW 7A, Line 17 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
27	Variable Transportation Costs	Line 24 times Line 25	$ 352	$ 324	$ 275	$ 257	$ 304	$ 356	$ 1,869
28									
29	Transportation Segment 3								
30	Union Pipeline (Contract M12205)								
31	Receipt Point: Dawn								
32	Delivery Point: Parkway (Interconnects with TransCanada)								
33	Received Volume	Line 15	185,386	170,681	144,979	135,047	160,082	187,452	983,626
34	Fuel Loss Rate	FXW 7A, Line 35 of Page 2	0.62%	0.42%	0.36%	0.35%	0.37%	0.74%	0.49%
35	Delivered Volume	Line 33 times (1 - Line 34)	184,229	169,970	144,462	134,574	159,493	186,055	978,783
36	Variable Transportation Rate	FXW 7A, Line 16 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Transportation Segment 4								
40	TransCanada Pipeline (Contract 41235)								
41	Receipt Point: Parkway								
42	Delivery Point: Iroquois								
43	Received Volume	Line 25	184,229	169,970	144,462	134,574	159,493	186,055	978,783
44	Fuel Loss Rate	FXW 7A, Line 33 of Page 2	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
45	Delivered Volume	Line 43 times (1 - Line 44)	181,926	167,846	142,656	132,892	157,499	183,730	966,549
46	Variable Transportation Rate	FXW 7A, Line 14 of Page 2	$ 0.0098	$ 0.0098	$ 0.0098	$ 0.0098	$ 0.0098	$ 0.0098	$ 0.0098
47	Variable Transportation Costs	Line 45 times Line 46	$ 1,783	$ 1,645	$ 1,398	$ 1,302	$ 1,543	$ 1,801	$ 9,472
48									
49	Transportation Segment 5								
50	Iroquois Pipeline (Contract R181001)								
51	Receipt Point: Waddington								
52	Delivery Point: Wright (Interconnection with Tennessee)								
53	Received Volume	Line 45	181,926	167,846	142,656	132,892	157,499	183,730	966,549
54	Fuel Loss Rate	FXW 7A, Line 23 of Page 2	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
55	Delivered Volume	Line 53 times (1 - Line 54)	181,744	167,678	142,513	132,759	157,342	183,546	965,582
56	Variable Transportation Rate	FXW 7A, Line 4 of Page 2	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052
57	Variable Transportation Costs	Line 55 times Line 56	$ 945	$ 872	$ 741	$ 690	$ 818	$ 954	$ 5,021
58									
59	Transporation Segment 6A								
60	Tennessee Gas Pipeline (Contract 31861)								
61	Receipt Point: Mendon								
62	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
63	Received Volume	Line 55	40,515	39,567	40,886	40,886	39,567	40,886	242,308
64	Fuel Loss Rate	FXW 7A, Line 31 of Page 2	0.96%	1.86%	1.86%	1.86%	1.86%	1.86%	1.71%
65	City Gate Delivered Volume	Line 63 times (1 - Line 64)	40,126	38,831	40,126	40,126	38,831	40,126	238,166
66	Variable Transportation Rate	FXW 7A, Line 12 of Page 2	$ 0.0019	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0227
67	Variable Transportation Costs	Line 65 times Line 66	$ 76	$ 1,045	$ 1,079	$ 1,079	$ 1,045	$ 1,079	$ 5,404
68									
69	Transportation Segment 6B								
70	Tennessee Gas Pipeline (Contract 31861)								
71	Receipt Point: Mendon								
72	Delivery Point: Pleasant St. (Interconnection with Granite)								
73	Received Volume	Line 55	24,818	24,164	24,970	24,970	24,164	24,970	148,055
74	Fuel Loss Rate	FXW 7A, Line 32 of Page 2	1.26%	1.86%	1.86%	1.86%	1.86%	1.86%	1.76%
75	Delivered Volume	Line 73 times (1 - Line 74)	24,505	23,715	24,505	24,505	23,715	24,505	145,450
76	Variable Transportation Rate	FXW 7A, Line 13 of Page 2	$ 0.0019	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0227
77	Variable Transportation Costs	Line 75 times Line 76	$ 47	$ 638	$ 659	$ 659	$ 638	$ 659	$ 3,300
78									
79	Transportation Segment 7B								
80	Granite State Gas Transmission (Contract 10-010-FT-NN)								
81	Receipt Point: Pleasant St.								
82	Delivery Point: Northern City Gates								
83	Received Volume	Line 75	24,505	23,715	24,505	24,505	23,715	24,505	145,450
84	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
85	City Gate Delivered Volume	Line 83 times (1 - Line 84)	24,419	23,632	24,419	24,419	23,632	24,419	144,941
86	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
87	Variable Transportation Costs	Line 85 times Line 86	$ 46	$ 45	$ 46	$ 46	$ 45	$ 46	$ 275
88									
89	Transportation Segment 6C								
90	Tennessee Gas Pipeline (Contract 41099)								
91	Receipt Point: Wright								
92	Delivery Point: Mendon (Interconnection with Algonquin)								
93	Received Volume	Line 55	116,411	103,946	76,657	66,903	93,610	117,690	575,218
94	Fuel Loss Rate	FXW 7A, Line 30 of Page 2	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%
95	Delivered Volume	Line 93 times (1 - Line 94)	114,246	102,013	75,231	65,659	91,869	115,501	564,519
96	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0373
97	Variable Transportation Costs	Line 95 times Line 96	$ 8,957	$ 2,744	$ 2,024	$ 1,766	$ 2,471	$ 3,107	$ 21,069
98									
99	Transportation Segment 7C								
100	Algonquin Gas Transmission (Contract 93200F)								
101	Receipt Point: Mendon								
102	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
103	Received Volume	Line 95	114,246	102,013	75,231	65,659	91,869	115,501	564,519
104	Fuel Loss Rate	FXW 7A, Line 20 of Page 2	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
105	City Gate Delivered Volume	Line 103 times (1 - Line 104)	113,424	101,279	74,690	65,186	91,207	114,669	560,455
106	Variable Transportation Rate	FXW 7A, Line 1 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
107	Variable Transportation Costs	Line 105 times Line 106	$ 216	$ 192	$ 142	$ 124	$ 173	$ 218	$ 1,065

Source of Supply: PNGTS (E. Hereford)
Delivered to Northern via PNGTS and Granite Pipelines

Line	**City Gate Delivered Costs**	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Purchased Volumes	Line 9	31,938	16,662	-	31,938	30,908	31,938	143,384
3	City Gate Delivered Volume	Line 35	31,826	16,603	-	31,826	30,800	31,826	142,882
4	Total Purchase Cost	Line 14	$ 161,159	$ 84,607	$ -	$ 164,641	$ 159,484	$ 166,333	$ 736,225
5	Variable Transportation Costs	Sum Lines 27 and 37	$ 121	$ 63	$ -	$ 121	$ 117	$ 121	$ 544
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 161,281	$ 84,671	$ -	$ 164,762	$ 159,601	$ 166,455	$ 736,769
7	Average Delivered Price	Line 5 divided by Line 2	$ 5.068	$ 5.100	#DIV/0!	$ 5.177	$ 5.182	$ 5.230	$ 5.156
8									
9	Portland Supply Costs								
10	Purchased Volumes	Sendout Optimization	31,938	16,662	-	31,938	30,908	31,938	143,384
11	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.707	$ 4.739	#DIV/0!	$ 4.816	$ 4.821	$ 4.869	$ 4.796
12	NYMEX Cost	Line 9 times Line 10	$ 150,332	$ 78,959	$ -	$ 153,814	$ 149,007	$ 155,506	$ 687,618
13	NYMEX Basis Price	FXW-7A, Line 4 of Page 1	$ 0.339	$ 0.339	#DIV/0!	$ 0.339	$ 0.339	$ 0.339	$ 0.339
14	NYMEX Basis Costs	Line 9 times Line 12	$ 10,827	$ 5,648	$ -	$ 10,827	$ 10,478	$ 10,827	$ 48,607
15	Total Purchase Price	Line 10 plus Line 12	$ 5.046	$ 5.078	#DIV/0!	$ 5.155	$ 5.160	$ 5.208	$ 5.135
16	Total Purchase Cost	Line 11 plus Line 13	$ 161,159	$ 84,607	$ -	$ 164,641	$ 159,484	$ 166,333	$ 736,225
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1								
20	PNGTS (Contract 1997-003)								
21	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
22	Delivery Point: Granite (Westbrook)								
23	Received Volume	Line 10	31,938	16,662	-	31,938	30,908	31,938	143,384
24	Fuel Loss Rate	FXW 7A, Line 24 of Page 2	0.00%	0.00%	#DIV/0!	0.00%	0.00%	0.00%	0.00%
25	Delivered Volume	Line 23 times (1 - Line 24)	31,938	16,662	-	31,938	30,908	31,938	143,384
26	Variable Transportation Rate	FXW 7A, Line 5 of Page 2	$ 0.0019	$ 0.0019	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
27	Variable Transportation Costs	Line 25 times Line 26	$ 61	$ 32	$ -	$ 61	$ 59	$ 61	$ 272
28									
29	Transportation Segment 2								
30	Granite State Gas Transmission (Contract 10-010-FT-NN)								
31	Receipt Point: Granite (Westbrook)								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	31,938	16,662	-	31,938	30,908	31,938	143,384
34	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	31,826	16,603	-	31,826	30,800	31,826	142,882
36	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
37	Variable Transportation Costs	Line 35 times Line 36	$ 60	$ 32	$ -	$ 60	$ 59	$ 60	$ 271

Source of Supply: Niagara (Interconnect of TransCanada and Tennessee Pipelines)
Delivered to Northern via Tennessee and Granite Pipelines
Delivered to Northern via Tennessee and Bay State Exhange Agreement

Line	**City Gate Delivered Costs**	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Purchased Volumes	Line 9	3,193	8,654	-	9,045	28,198	84,939	134,029
3	City Gate Delivered Volume	Sum Lines 25, 55 and 45	3,133	8,493	-	8,872	27,661	83,287	131,446
4	Total Purchase Cost	Line 14	$ 15,868	$ 43,287	$ -	$ 45,939	$ 143,360	$ 435,908	$ 684,363
5	Variable Transportation Costs	Sum Lines 27, 57, 37 and 47	$ 246	$ 228	$ -	$ 242	$ 751	$ 2,281	$ 3,748
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 16,114	$ 43,516	$ -	$ 46,181	$ 144,112	$ 438,190	$ 688,111
7	Average Delivered Price	Line 5 divided by Line 2	$ 5.143	$ 5.124	#DIV/0!	$ 5.205	$ 5.210	$ 5.261	$ 5.235
8									
9	<u>Niagara Supply Costs</u>								
10	Purchased Volumes	Sendout Optimization	3,193	8,654	-	9,045	28,198	84,939	134,029
11	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.707	$ 4.739	#DIV/0!	$ 4.816	$ 4.821	$ 4.869	$ 4.843
12	NYMEX Cost	Line 9 times Line 10	$ 15,028	$ 41,011	$ -	$ 43,560	$ 135,944	$ 413,569	$ 649,113
13	NYMEX Basis Price	FXW-7A, Line 5 of Page 1	$ 0.263	$ 0.263	#DIV/0!	$ 0.263	$ 0.263	$ 0.263	$ 0.263
14	NYMEX Basis Costs	Line 9 times Line 12	$ 840	$ 2,276	$ -	$ 2,379	$ 7,416	$ 22,339	$ 35,250
15	Total Purchase Price	Line 10 plus Line 12	$ 4.970	$ 5.002	#DIV/0!	$ 5.079	$ 5.084	$ 5.132	$ 5.106
16	Total Purchase Cost	Line 11 plus Line 13	$ 15,868	$ 43,287	$ -	$ 45,939	$ 143,360	$ 435,908	$ 684,363
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 1A								
20	Tennessee Gas Pipeline (Contract 5292)								
21	Receipt Point: Niagara								
22	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
23	Received Volume	Line 9	1,342	5,274	-	4,835	14,870	37,862	64,183
24	Fuel Loss Rate	FXW 7A, Line 30 of Page 2	1.86%	1.86%	#DIV/0!	1.86%	1.86%	1.86%	1.86%
25	City Gate Delivered Volume	Line 23 times (1 - Line 24)	1,317	5,175	-	4,745	14,594	37,158	62,989
26	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	$ 0.0269	#DIV/0!	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0280
27	Variable Transportation Costs	Line 25 times Line 26	$ 103	$ 139	$ -	$ 128	$ 393	$ 1,000	$ 1,762
28									
29	Transportation Segment 1B								
30	Tennessee Gas Pipeline (Contract 39375)								
31	Receipt Point: Niagara								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 9	-	-	-	1,490	3,698	21,031	26,220
34	Fuel Loss Rate	FXW 7A, Line 30 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	1.86%	1.86%	1.86%	1.86%
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	1,463	3,629	20,640	25,732
36	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ 39	$ 98	$ 555	$ 692
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 10-010-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	-	-	-	1,463	3,629	20,640	25,732
44	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	-	-	-	1,458	3,616	20,568	25,642
46	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ -	$ -	$ 3	$ 7	$ 39	$ 49
48									
49	Transportation Segment 1C								
50	Tennessee Gas Pipeline (Contract 46314)								
51	Receipt Point: Niagara								
52	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
53	Received Volume	Line 9	1,851	3,381	-	2,720	9,630	26,046	43,627
54	Fuel Loss Rate	FXW 7A, Line 30 of Page 2	1.86%	1.86%	#DIV/0!	1.86%	1.86%	1.86%	1.86%
55	City Gate Delivered Volume	Line 53 times (1 - Line 54)	1,816	3,318	-	2,669	9,451	25,561	42,816
56	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	$ 0.0269	#DIV/0!	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0291
57	Variable Transportation Costs	Line 55 times Line 56	$ 142	$ 89	$ -	$ 72	$ 254	$ 688	$ 1,245

Source of Supply: Tennessee Production
Delivered to Northern via Tennessee and Granite Pipelines

Line	**City Gate Delivered Costs**	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
1	City Gate Volumes - Z0	Line 2 of Page 5	-	-	-	-	-	-	-
2	City Gate Volumes - Z1	Line 2 of Page 6	91,315	-	-	5,860	4,135	55,521	156,831
3	Total City Gate Volumes	Line 1 plus Line 2	91,315	-	-	5,860	4,135	55,521	156,831
4	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 469,405	$ -	$ -	$ 30,609	$ 21,619	$ 293,181	$ 814,815
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 469,405	$ -	$ -	$ 30,609	$ 21,619	$ 293,181	$ 814,815
7	Average Delivered Price	Line 6 divided by Line 3	$ 5.140	#DIV/0!	#DIV/0!	$ 5.224	$ 5.229	$ 5.281	$ 5.195

Source of Supply: Tennessee Zone 0
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	2011 Off-Peak May-11	2011 Off-Peak Jun-11	2011 Off-Peak Jul-11	2011 Off-Peak Aug-11	2011 Off-Peak Sep-11	2011 Off-Peak Oct-11	2011 Off-Peak
2	Purchased Volumes	Line 33	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Line 45	-	-	-	-	-	-	-
4	Total Purchase Price	Line 25	$ 4.610	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 4.610
5	Total Purchase Cost	Line 2 times Line 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Variable Transportation Costs	Sum Lines 37 and 47	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Average Delivered Price	Line 6 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
9									
10	**Tennessee Northern Storage Injection Meter Deliveries**								
11	Purchased Volumes	Line 53	540	-	-	-	-	-	540
12	Storage Delivered Volume	Line 55	509	-	-	-	-	-	509
13	Total Purchase Price	Line 25	$ 4.610	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 4.610
14	Total Purchase Cost	Line 10 times Line 12	$ 2,491	$ -	$ -	$ -	$ -	$ -	$ 2,491
15	Variable Transportation Costs	Line 57	$ 58	$ -	$ -	$ -	$ -	$ -	$ 58
16	Total Storage Delivered Costs	Line 13 plus Line 14	$ 2,549	$ -	$ -	$ -	$ -	$ -	$ 2,549
17	Average Delivered Price	Line 15 divided by Line 11	$ 5.008	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.008
18									
19	Tennessee Zone 0 Supply Costs								
20	Purchased Volumes	Sendout Optimization	540	-	-	-	-	-	540
21	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.707	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 4.707
22	NYMEX Cost	Line 25 times Line 26	$ 2,543	$ -	$ -	$ -	$ -	$ -	$ 2,543
23	NYMEX Basis Price	FXW-7A, Line 6 of Page 1	$ (0.097)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ (0.097)
24	NYMEX Basis Costs	Line 25 times Line 28	$ (52)	$ -	$ -	$ -	$ -	$ -	$ (52)
25	Total Purchase Price	Line 26 plus Line 28	$ 4.610	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 4.610
26	Total Purchase Cost	Line 27 plus Line 29	$ 2,491	$ -	$ -	$ -	$ -	$ -	$ 2,491
27									
28	Transportation Fuel Losses and Variable Charges								
29	Transportation Segment 1A								
30	Tennessee Gas Pipeline (Contract 5083)								
31	Receipt Point: Tennessee Zone 0								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 20	-	-	-	-	-	-	-
34	Fuel Loss Rate	FXW 7A, Line 26 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	FXW 7A, Line 7 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Transportation Segment 2A								
40	Granite State Gas Transmission (Contract 10-010-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	-	-	-	-	-	-	-
44	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	#DIV/0!
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	-	-	-	-	-	-	-
46	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!
47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48									
49	Transportation Segment 3								
50	Tennessee Gas Pipeline (Contract 5083)								
51	Receipt Point: Tennessee Zone 0								
52	Delivery Point: Tennessee Market Area Storage								
53	Received Volume	Line 25 minus Line 38	540	-	-	-	-	-	540
54	Fuel Loss Rate	FXW 7A, Line 25 of Page 2	5.80%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	5.80%
55	Storage Delivered Volume	Line 53 times (1 - Line 54)	509	-	-	-	-	-	509
56	Variable Transportation Rate	FXW 7A, Line 6 of Page 2	$ 0.1137	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1137
57	Variable Transportation Costs	Line 55 times Line 56	$ 58	$ -	$ -	$ -	$ -	$ -	$ 58

Source of Supply: Tennessee Zone L
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Purchased Volumes	Line 33	98,185	-	-	6,301	4,446	59,698	168,629
3	City Gate Delivered Volume	Line 45	91,315	-	-	5,860	4,135	55,521	156,831
4	Total Purchase Price	Line 25	$ 4.637	$ 4.669	$ 4.721	$ 4.746	$ 4.751	$ 4.799	$ 4.695
5	Total Purchase Cost	Line 2 times Line 3	$ 455,284	$ -	$ -	$ 29,903	$ 21,121	$ 286,490	$ 792,799
6	Variable Transportation Costs	Sum Lines 37 and 47	$ 14,121	$ -	$ -	$ 706	$ 498	$ 6,691	$ 22,016
7	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 469,405	$ -	$ -	$ 30,609	$ 21,619	$ 293,181	$ 814,815
8	Average Delivered Price	Line 6 divided by Line 2	$ 5.140	#DIV/0!	#DIV/0!	$ 5.224	$ 5.229	$ 5.281	$ 5.195
9									
10	**Tennessee Northern Storage Injection Meter Deliveries**								
11	Purchased Volumes	Line 53	56,773	55,461	57,310	45,271	-	-	214,815
12	Storage Delivered Volume	Line 55	53,901	52,655	54,410	42,980	-	-	203,945
13	Total Purchase Price	Line 25	$ 4.637	$ 4.669	$ 4.721	$ 4.746	$ 4.751	$ 4.799	$ 4.695
14	Total Purchase Cost	Line 10 times Line 12	$ 263,259	$ 258,947	$ 270,558	$ 214,855	$ -	$ -	$ 1,007,619
15	Variable Transportation Costs	Line 57	$ 5,568	$ 4,397	$ 4,543	$ 3,589	$ -	$ -	$ 18,097
16	Total Storage Delivered Costs	Line 13 plus Line 14	$ 268,827	$ 263,343	$ 275,102	$ 218,444	$ -	$ -	$ 1,025,715
17	Average Delivered Price	Line 15 divided by Line 11	$ 4.987	$ 5.001	$ 5.056	$ 5.082	#DIV/0!	#DIV/0!	$ 5.029
18									
19	Tennessee Zone L Supply Costs								
20	Purchased Volumes	Sendout Optimization	154,959	55,461	57,310	51,571	4,446	59,698	383,444
21	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.707	$ 4.739	$ 4.791	$ 4.816	$ 4.821	$ 4.869	$ 4.765
22	NYMEX Cost	Line 25 times Line 26	$ 729,390	$ 262,829	$ 274,570	$ 248,367	$ 21,432	$ 290,669	$ 1,827,258
23	NYMEX Basis Price	FXW-7A, Line 7 of Page 1	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)
24	NYMEX Basis Costs	Line 25 times Line 28	$ (10,847)	$ (3,882)	$ (4,012)	$ (3,610)	$ (311)	$ (4,179)	$ (26,841)
25	Total Purchase Price	Line 26 plus Line 28	$ 4.637	$ 4.669	$ 4.721	$ 4.746	$ 4.751	$ 4.799	$ 4.695
26	Total Purchase Cost	Line 27 plus Line 29	$ 718,543	$ 258,947	$ 270,558	$ 244,757	$ 21,121	$ 286,490	$ 1,800,417
27									
28	Transportation Fuel Losses and Variable Charges								
29	Transportation Segment 1B								
30	Tennessee Gas Pipeline (Contract 5083)								
31	Receipt Point: Tennessee Zone L								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 20	98,185	-	-	6,301	4,446	59,698	168,629
34	Fuel Loss Rate	FXW 7A, Line 28 of Page 2	6.67%	#DIV/0!	#DIV/0!	6.67%	6.67%	6.67%	6.67%
35	Delivered Volume	Line 33 times (1 - Line 34)	91,636	-	-	5,880	4,149	55,716	157,382
36	Variable Transportation Rate	FXW 7A, Line 9 of Page 2	$ 0.1522	#DIV/0!	#DIV/0!	$ 0.1182	$ 0.1182	$ 0.1182	$ 0.1380
37	Variable Transportation Costs	Line 35 times Line 36	$ 13,947	$ -	$ -	$ 695	$ 490	$ 6,586	$ 21,718
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 10-010-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	91,636	-	-	5,880	4,149	55,716	157,382
44	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	91,315	-	-	5,860	4,135	55,521	156,831
46	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
47	Variable Transportation Costs	Line 45 times Line 46	$ 173	$ -	$ -	$ 11	$ 8	$ 105	$ 298
48									
49	Transportation Segment 3								
50	Tennessee Gas Pipeline (Contract 5083)								
51	Receipt Point: Tennessee Zone L								
52	Delivery Point: Tennessee Market Area Storage								
53	Received Volume	Line 25 minus Line 38	56,773	55,461	57,310	45,271	-	-	214,815
54	Fuel Loss Rate	FXW 7A, Line 27 of Page 2	5.06%	5.06%	5.06%	5.06%	#DIV/0!	#DIV/0!	5.06%
55	Storage Delivered Volume	Line 53 times (1 - Line 54)	53,901	52,655	54,410	42,980	-	-	203,945
56	Variable Transportation Rate	FXW 7A, Line 8 of Page 2	$ 0.1033	$ 0.0835	$ 0.0835	$ 0.1033	#DIV/0!	#DIV/0!	$ 0.0887
57	Variable Transportation Costs	Line 55 times Line 56	$ 5,568	$ 4,397	$ 4,543	$ 3,589	$ -	$ -	$ 18,097

Source of Supply: Tennessee FS-MA Inventory
Delivered to Northern via Tennessee and Granite Pipelines

Line	**City Gate Delivered Costs**	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Gross Withdrawn Volume	Line 10	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Line 36	-	-	-	-	-	-	-
4	Total Withdrawal Costs	Line 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Sum Lines 28 and 38	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
8									
9	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
10	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
11	Withdrawal Rate		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
12	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Inventory Rate	FXW-8, Page 1	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
14	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Withdrawal Fuel Losses		-	-	-	-	-	-	-
16	Net Withdrawn Volume	Line 9 minus Line 14	-	-	-	-	-	-	-
17	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18									
19	Transportation Fuel Losses and Variable Charges								
20	Transportation Segment 2								
21	Tennessee Gas Pipeline (Contract 5265)								
22	Receipt Point: Tennessee FS-MA Withdrawal Meter								
23	Delivery Point: Pleasant St. (Interconnection with Granite)								
24	Received Volume	Line 16	-	-	-	-	-	-	-
25	Fuel Loss Rate	FXW 7A, Line 10 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
26	Delivered Volume	Line 24 times (1 - Line 25)	-	-	-	-	-	-	-
27	Variable Transportation Rate	FXW 7A, Line 10 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29									
30	Transportation Segment 3								
31	Granite State Gas Transmission (Contract 10-010-FT-NN)								
32	Receipt Point: Pleasant St.								
33	Delivery Point: Northern City Gates								
34	Received Volume	Line 26	-	-	-	-	-	-	-
35	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	#DIV/0!
36	City Gate Delivered Volume	Line 34 times (1 - Line 35)	-	-	-	-	-	-	-
37	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!
38	Variable Transportation Costs	Line 36 times Line 37	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Washington 10 Inventory
Delivered to Northern via TransCanada, PNGTS and Granite Pipelines

Line	**City Gate Delivered Costs**	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Gross Withdrawn Volume	Line 10	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Line 66	-	-	-	-	-	-	-
4	Total Withdrawal Costs	Line 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Sum Lines 28, 38, 48, 58 and 68	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
8									
9	Washington 10 Withdrawn Inventory (Segment 1)								
10	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
11	Withdrawal Rate		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
12	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Inventory Rate		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
14	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Withdrawal Fuel Losses		-	-	-	-	-	-	-
16	Net Withdrawn Volume	Line 9 minus Line 14	-	-	-	-	-	-	-
17	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18									
19	Transportation Fuel Losses and Variable Charges								
20	Transportation Segment 2A								
21	Vector Pipeline (Contract CRL-NUI-0725)								
22	Receipt Point: Washington 10 Withdrawal Meter								
23	Delivery Point: Dawn (Interconnects with TransCanada)								
24	Received Volume	Line 16	-	-	-	-	-	-	-
25	Fuel Loss Rate	FXW 7A, Line 18 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
26	Delivered Volume	Line 24 times (1 - Line 25)	-	-	-	-	-	-	-
27	Variable Transportation Rate	FXW 7A, Line 18 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29									
30	Transportation Segment 2B								
31	Vector Pipeline (Contract CRL-NUI-0727)								
32	Receipt Point: Washington 10 Withdrawal Meter								
33	Delivery Point: Union Dawn (Interconnects with TransCanada)								
34	Received Volume	Line 26	-	-	-	-	-	-	-
35	Fuel Loss Rate	FXW 7A, Line 18 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
36	Delivered Volume	Line 34 times (1 - Line 35)	-	-	-	-	-	-	-
37	Variable Transportation Rate	FXW 7A, Line 18 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
38	Variable Transportation Costs	Line 36 times Line 37	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39									
40	Transportation Segment 3								
41	TransCanada Pipeline (Contract 33322)								
42	Receipt Point: Union Dawn								
43	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)								
44	Received Volume	Line 36	-	-	-	-	-	-	-
45	Fuel Loss Rate	FXW 7A, Line 15 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
46	Delivered Volume	Line 44 times (1 - Line 45)	-	-	-	-	-	-	-
47	Variable Transportation Rate	FXW 7A, Line 15 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
48	Variable Transportation Costs	Line 46 times Line 47	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49									
50	Transportation Segment 4								
51	PNGTS (Contract 1997-004)								
52	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
53	Delivery Point: Granite (Westbrook, Newington, Eliot)								
54	Received Volume	Line 46	-	-	-	-	-	-	-
55	Fuel Loss Rate	FXW 7A, Line 5 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
56	Delivered Volume	Line 54 times (1 - Line 55)	-	-	-	-	-	-	-
57	Variable Transportation Rate	FXW 7A, Line 5 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
58	Variable Transportation Costs	Line 56 times Line 57	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59									
60	Transportation Segment 5								
61	Granite State Gas Transmission (Contract 10-010-FT-NN)								
62	Receipt Point: Westbrook, Newington, Eliot								
63	Delivery Point: Northern City Gates								
64	Received Volume	Line 56	-	-	-	-	-	-	-
65	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	#DIV/0!
66	City Gate Delivered Volume	Line 64 times (1 - Line 65)	-	-	-	-	-	-	-
67	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!
68	Variable Transportation Costs	Line 66 times Line 67	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Peaking Supply 1
Delivered to Northern via Tennessee and Granite Pipelines
Delivered to Northern in liquid form via trucks

Line	City Gate Delivered Costs	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Purchased Volumes	Line 11	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Line 34	-	-	-	-	-	-	-
4	Total Purchase Price	Line 25	$ 5.927	$ 5.959	$ 6.011	$ 6.036	$ 6.041	$ 6.089	$ 6.001
5	Total Purchase Cost	Line 1 times Line 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Variable Transportation Costs	Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Total City Gate Delivered Costs	Line 4 plus Line 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Average Delivered Price	Line 6 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
9									
10	**LNG Storage Deliveries**								
11	Purchased Volumes	Line 42	2,429	1,350	1,395	1,395	1,350	1,395	9,314
12	Storage Delivered Volume	Line 44	2,429	1,350	1,395	1,395	1,350	1,395	9,314
13	Total Purchase Price	Line 25	$ 5.927	$ 5.959	$ 6.011	$ 6.036	$ 6.041	$ 6.089	$ 6.001
14	Total Purchase Cost	Line 10 times Line 12	$ 14,397	$ 8,045	$ 8,385	$ 8,420	$ 8,155	$ 8,494	$ 55,897
15	Variable Transportation Costs	Line 46	$ 2,283	$ 1,269	$ 1,311	$ 1,311	$ 1,269	$ 1,311	$ 8,755
16	Total Storage Delivered Costs	Line 13 plus Line 14	$ 16,681	$ 9,314	$ 9,697	$ 9,732	$ 9,424	$ 9,805	$ 64,652
17	Average Delivered Price	Line 15 divided by Line 11	$ 6.867	$ 6.899	$ 6.951	$ 6.976	$ 6.981	$ 7.029	$ 6.941
18									
19	Peaking Supply 1 Costs (Segment 1)								
20	Purchased Volumes	Sendout Optimization	2,429	1,350	1,395	1,395	1,350	1,395	9,314
21	Peaking Supply 1 Prices	Contract Rate	$ 5.927	$ 5.959	$ 6.011	$ 6.036	$ 6.041	$ 6.089	$ 6.001
22	Peaking Supply 1 Costs	Line 19 times Line 20	$ 14,397	$ 8,045	$ 8,385	$ 8,420	$ 8,155	$ 8,494	$ 55,897
23	NYMEX Basis Price	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	NYMEX Basis Costs	Line 19 times Line 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Total Purchase Price	Line 20 plus Line 22	$ 5.927	$ 5.959	$ 6.011	$ 6.036	$ 6.041	$ 6.089	$ 6.001
26	Total Purchase Cost	Line 24 times (1 - Line 25)	$ 14,397	$ 8,045	$ 8,385	$ 8,420	$ 8,155	$ 8,494	$ 55,897
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Sendout Optimization	-	-	-	-	-	-	-
33	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	#DIV/0!
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37									
38	Transportation Segment 3								
39	Trucking Contract (TransGas)								
40	Receipt Point: Distrigas Terminal								
41	Delivery Point: Northern LNG Facility (Lewiston, ME)								
42	Received Volume	Line 19 minus Line 31	2,429	1,350	1,395	1,395	1,350	1,395	9,314
43	Fuel Loss Rate	Company Forecast	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
44	Storage Delivered Volume	Line 42 times (1 - Line 43)	2,429	1,350	1,395	1,395	1,350	1,395	9,314
45	Variable Transportation Rate	Company Forecast	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400
46	Variable Transportation Costs	Line 44 times Line 45	$ 2,283	$ 1,269	$ 1,311	$ 1,311	$ 1,269	$ 1,311	$ 8,755

Source of Supply: Northern LNG Inventory
On-System Storage

Line	**City Gate Delivered Costs**	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Gross Withdrawn Volume	Line 10	1,395	1,350	1,395	1,395	1,350	1,395	8,280
3	City Gate Delivered Volume	Line 16	1,395	1,350	1,395	1,395	1,350	1,395	8,280
4	Total Withdrawal Costs	Line 17	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 46,100
5	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 46,100
7	Average Delivered Price	Line 5 divided by Line 2	$ 5.104	$ 5.311	$ 5.506	$ 5.681	$ 5.831	$ 5.973	$ 5.568
8									
9	Northern LNG Withdrawn Inventory								
10	Gross Withdrawn Volume	Sendout Optimization	1,395	1,350	1,395	1,395	1,350	1,395	8,280
11	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Inventory Rate		$ 5.1039	$ 5.3112	$ 5.5061	$ 5.6808	$ 5.8310	$ 5.9734	$ 5.5677
14	Withdrawn Inventory Value	Line 9 times Line 12	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 46,100
15	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
16	Net Withdrawn Volume	Line 9 minus Line 14	1,395	1,350	1,395	1,395	1,350	1,395	8,280
17	Total Withdrawal Costs	Line 11 plus Line 13	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 46,100

Source of Supply: Peaking Supply 2
Delivered to Northern via Granite Pipeline

Line	**City Gate Delivered Costs**	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	2011 Off-Peak
2	Purchased Volumes	Line 9	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Line 25	-	-	-	-	-	-	-
4	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
8									
9	Peaking Supply 2 Costs								
10	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
11	Monthly NYMEX Price		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Price		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
14	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Purchase Price	Line 10 plus Line 12	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
16	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1								
20	Granite State Gas Transmission (Contract 10-010-FT-NN)								
21	Receipt Point: Newington or Westbrook								
22	Delivery Point: Northern City Gates								
23	Received Volume	Line 9	-	-	-	-	-	-	-
24	Fuel Loss Rate	FXW 7A, Line 22 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	#DIV/0!
25	City Gate Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for January 20, 2011

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
CHICAGO	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050
PNGTS	$0.339	$0.339	$0.339	$0.339	$0.339	$0.339
NIAGARA	$0.263	$0.263	$0.263	$0.263	$0.263	$0.263
TGP Z0	($0.097)	($0.097)	($0.097)	($0.097)	($0.097)	($0.097)
TGP Z1	($0.070)	($0.070)	($0.070)	($0.070)	($0.070)	($0.070)
FPL PEAK						
W10 Supply	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050
NYMEX NG	$4.707	$4.739	$4.791	$4.816	$4.821	$4.869

Northern Utilities, Inc.
Pipeline Variable Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	May-11 Variable Commodity Rate	Jun-11 Variable Commodity Rate	Jul-11 Variable Commodity Rate	Aug-11 Variable Commodity Rate	Sep-11 Variable Commodity Rate	Oct-11 Variable Commodity Rate	Notes	Commodity Rate Support
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		Pg 4
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131		Pg 4
3	Granite	FT-NN	N/A	N/A	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		Pg 6
4	Iroquois	RTS-1	Zone 1	Zone 1	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	1	Pgs 7 & 8
5	PNGTS	FT	N/A	N/A	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		Pg 9
6	Tennessee	FT-A	Zone 0	Zone 4	$ 0.1137	$ 0.0991	$ 0.0991	$ 0.0991	$ 0.0991	$ 0.0991	2	Pgs 10 & 11
7	Tennessee	FT-A	Zone 0	Zone 6	$ 0.1627	$ 0.1361	$ 0.1361	$ 0.1361	$ 0.1361	$ 0.1361	2	Pgs 10 & 11
8	Tennessee	FT-A	Zone L	Zone 4	$ 0.1033	$ 0.0835	$ 0.0835	$ 0.0835	$ 0.0835	$ 0.0835	2	Pgs 10 & 11
9	Tennessee	FT-A	Zone L	Zone 6	$ 0.1522	$ 0.1182	$ 0.1182	$ 0.1182	$ 0.1182	$ 0.1182	2	Pgs 10 & 11
10	Tennessee	FT-A	Zone 4	Zone 6	$ 0.0853	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368	2	Pgs 10 & 11
11	Tennessee	FT-A	Zone 5	Zone 6	$ 0.0784	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	2	Pgs 10 & 11
12	Tennessee	NET	Segment 3	Segment 3	$ 0.0019	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	3	Pg 13 & 11
13	Tennessee	NET	Segment 3	Segment 4	$ 0.0019	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	3	Pg 13 & 11
14	TransCanada	FT	Parkway	Iroquois	$ 0.0098	$ 0.0098	$ 0.0098	$ 0.0098	$ 0.0098	$ 0.0098		Pg 17
15	TransCanada	FT	Dawn	E. Hereford	$ 0.0647	$ 0.0647	$ 0.0647	$ 0.0647	$ 0.0647	$ 0.0647		Pg 17
16	Union	M12	Dawn	Parkway	$ -	$ -	$ -	$ -	$ -	$ -	4	
17	Vector	FT-1	Alliance	W-10 Storage	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		Pg 24
18	Vector	FT-1	W-10 Storage	Dawn	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		Pg 24
19	Vector	FT-1	Alliance	Dawn	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		Pg 24

Line	Pipeline	Rate Schedule	Receipt	Delivery	May-11 Fuel Rates	Jun-11 Fuel Rates	Jul-11 Fuel Rates	Aug-11 Fuel Rates	Sep-11 Fuel Rates	Oct-11 Fuel Rates	Notes	Fuel Rate Support
20	Algonquin	AFT-1 (AFT-2)	N/A	N/A	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%		Pg 5
21	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%		Pg 5
22	Granite	FT-NN	N/A	N/A	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%		Pg 6
23	Iroquois	RTS-1	Zone 1	Zone 1	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%		Estimated
24	PNGTS	FT	N/A	N/A	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		Estimated
25	Tennessee	FT-A	Zone 0	Zone 4	5.80%	5.80%	5.80%	5.80%	5.80%	5.80%		Pg 12 & 15
26	Tennessee	FT-A	Zone 0	Zone 6	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%		Pg 12 & 15
27	Tennessee	FT-A	Zone L	Zone 4	5.06%	5.06%	5.06%	5.06%	5.06%	5.06%		Pg 12 & 15
28	Tennessee	FT-A	Zone L	Zone 6	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%		Pg 12 & 15
29	Tennessee	FT-A	Zone 4	Zone 6	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%		Pg 12 & 15
30	Tennessee	FT-A	Zone 5	Zone 6	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%		Pg 12 & 15
31	Tennessee	NET	Segment 3	Segment 3	0.96%	1.86%	1.86%	1.86%	1.86%	1.86%		Pg 14 & 15
32	Tennessee	NET	Segment 3	Segment 4	1.26%	1.86%	1.86%	1.86%	1.86%	1.86%		Pg 14 & 15
33	TransCanada	FT	Parkway	Iroquois	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%		Pg 23
34	TransCanada	FT	Dawn	E. Hereford	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%		Pg 23
35	Union	M12	Dawn	Parkway	0.62%	0.42%	0.36%	0.35%	0.37%	0.75%		Pg 21
36	Vector	FT-1	Alliance	W-10 Storage	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%		Pg 25
37	Vector	FT-1	W-10 Storage	Dawn	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%		Pg 25
38	Vector	FT-1	Alliance	Dawn	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%		Pg 25

Note 1: Iroquois Commodity Rates are equal to the RTS Commodity rate on Page 7 plus the ACA Adjustment and Deferred Asset Surcharge on Page 8.

Note 2: For Receipts from Zone L, the rates for Receipts from Zone 1 apply. Tennessee filed for new rates in FERC Docket No. RP11-1566. The proposed rates will take effect on 6/1/2011 and are found on page 11.

Note 3: In the Tennessee rate case filed in FERC Docket No. RP11-1566, Tennessee has proposed that the NET-284 rates be set equal to the FT-A rates. (Page 16) This change will take effect 6/1/2011.

Note 4: Union does not charge a variable transportation rate.

Northern Utilities, Inc. Underground Storage Variable Rates							
Line	Storage	Rate Schedule	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss	Reference
1	Tennessee (Until 6/1/2011)	FS-MA	$ 0.0102	0.00%	$ 0.0102	1.49%	Page 26
2	Tennessee (Effective 6/1/2011)	FS-MA	$ 0.0102	0.00%	$ 0.0102	1.49%	Page 27
3	Washington 10	Firm Storage	$ -	0.40%	$ -	1.00%	Pages 28 & 29

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2010

•RATE SCHEDULE AFT-1

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-2/F-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-4)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(STB/SS-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(FTP)	$11.8368	$0.0019	$0.0019	$0.3911	$0.0019	$0.3892
(PSS-T)	$ 9.7854	$0.0019	$0.0019	$0.3236	$0.0019	$0.3217
(AFT-2)	$ 6.1138	$0.0019	$0.0019	$0.2029	$0.0019	$0.2010
(AFT-3)	$10.7554	$0.0019	$0.0019	$0.3555	$0.0019	$0.3536
(AFT-5)	$12.6265	$0.0019	$0.0019	$0.4170	$0.0019	$0.4151
(ITP)	$13.0110	$0.0019	$0.0019	$0.4297	$0.0019	$0.4278
(X-35)	$10.2027	$0.0019	$0.0019	$0.3373	$0.0019	$0.3354
X-39	$13.2089	$0.0019	$0.0019	$0.4362	$0.0019	$0.4343
Incremental Surcharges						
Hubline	$ 1.8607	$0.0000	$0.0000	$0.0000	$0.0000	$0.0612
Secondary 1/		$0.0612	$0.0000			
Tiverton	$ 1.6424	$0.0000	$0.0000	$0.0000	$0.0000	$0.0540
Ramapo	$ 7.5608	$0.0000	$0.0000	$0.2486	$0.0000	$0.2486

•RATE SCHEDULE AFT-1S

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-2/F-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-4)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0031	$0.0864
(STB/SS-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			

•OTHER FIRM RATE SCHEDULES

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
AFT-E	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0058		$0.0600		
AFT-4	$ 3.5211	$0.0032		$0.1190		
AFT-CL:						
Canal	$ 2.0858	$0.0019	$0.0019	$0.0705	$0.0019	$0.0686
Middletown	$ 3.2764	$0.0019	$0.0019	$0.1096	$0.0019	$0.1077
Cleary	$ 1.4529	$0.0019	$0.0019	$0.0497	$0.0019	$0.0478
Lake Road	$ 0.6476	$0.0019	$0.0019	$0.0232	$0.0019	$0.0213
Brayton Pt.	$ 1.2700	$0.0019	$0.0019	$0.0437	$0.0019	$0.0418
Manchester	$ 2.4500	$0.0019	$0.0019	$0.0824	$0.0019	$0.0805
Bellingham	$ 0.9714	$0.0019	$0.0019	$0.0338	$0.0019	$0.0319
Phelps Dodge	$ 0.0000	$0.0185	$0.0019	$0.0185	$0.0019	$0.0000
Cape Cod	$ 9.0501	$0.0019	$0.0019	$0.2994	$0.0019	$0.2975
Northeast Gateway	$ 4.3449	$0.0019	$0.0019	$0.1447	$0.0019	$0.1428
J-2 Facility	$ 4.9077	$0.0019	$0.0019	$0.1632	$0.0019	$0.1613
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun	
	Max	Min	Max	Min
AIT-1	$0.2440	$0.0095	$0.2440	$0.0095
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0437	$0.0019	$0.0437	$0.0019
Manchester	$0.0824	$0.0019	$0.0824	$0.0019
Canal	$0.0705	$0.0019	$0.0705	$0.0019
Cape Cod	$0.2994	$0.0019	$0.2994	$0.0019
Northeast Gateway	$0.1447	$0.0019	$0.1447	$0.0019
J-2 Facility	$0.1632	$0.0019	$0.1632	$0.0019
PAL	$0.2440	$0.0000	$0.0000	$0.0000

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charge of $0.0019.

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
System Services		
Winter	Dec 1 - Mar 31	1.02%
Spring, Summer and Fall	Apr 1 - Nov 30	0.72%
Incremental Ramapo Services		
Winter	Dec 1 - Mar 31	1.92%
Spring, Summer and Fall	Apr 1 - Nov 30	1.31%

1/ Hubline Surcharge applicable to all customers utilizing secondary receipt points between and including Beverly and Weymouth and/or utilizing secondary delivery points between Beverly and Weymouth,including Beverly and excluding Weymouth,and in addition to other applicable charges.

•The Summary of Rates serves as a handy reference and does not replace Algonquin's Tariff. The rates are subject to commission approval.

4.2 Rate Schedule FT-NN
Firm Transportation Service
Currently Effective Rates

	$/Dth		
	Base Tariff Rate	ACA Adj.	Total Current Rate
Reservation Charge:			
Maximum	$2.8000		$2.8000
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0019	$0.0019
Minimum	$0.0000	$0.0019	$0.0019
Authorized Overrun Commodity Charge:			
Maximum	$0.0921	$0.0019	$0.0940
Minimum	$0.0000	$0.0019	$0.0019
Fuel and Losses Percentage			0.35%
Volumetric Reservation Charge			
Maximum	$0.0921	$0.0019	$0.0940
Minimum	$0.0000	$0.0019	$0.0019

Previous Next

Iroquois Gas Transmission System, L.P. Thirty First Revised Sheet No. 4

FERC Gas Tariff Superseding

FIRST REVISED VOLUME NO. 1 Thirtieth Revised Sheet No. 4

--------------- RATES (All in $ Per Dth) ----------------

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/ Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$\boxed{\$0.0030}$
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Jan 26, 2009 Effective: Jan 27, 2009

Previous Next

Previous Next

Iroquois Gas Transmission System, L.P.	Twenty-Fourth Revised Sheet No. 4a
FERC Gas Tariff	Superseding
FIRST REVISED VOLUME NO. 1	Twenty-Third Sheet No. 4a

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity	0.0019

DEFERRED ASSET SURCHARGE:

Commodity

Zone 1	0.0003
Zone 2	0.0002
Inter-Zone	0.0005

MEASUREMENT VARIANCE/FUEL USE FACTOR:

Minimum	0.00%
Maximum (Non-Eastchester Shipper)	1.00%
Maximum (Eastchester Shipper)	4.50%
Maximum (Brookfield Shipper)	1.20%

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Sep 30, 2009 Effective: Nov 01, 2009

Previous Next

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$40.2456	---------	$40.2456
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$76.4666	---------	$76.4666
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0019	$\boxed{\$00.0019}$
	-- Minimum	$00.0000	$00.0019	$00.0019
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$27.0128	---------	$27.0128
	--Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.4350	$00.0019	$00.4369
	--Minimum	$00.0000	$00.0019	$00.0019

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

Minimum	down to -1.00%
Maximum	up to +1.00%

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

Tennessee Gas Pipeline Company
FERC Gas Tariff
Sixth Revised Volume No. 1

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0458		$0.0688	$0.0899	$0.0997	$0.1137	$0.1250	$0.1627
L		$0.0305						
1	$0.0688		$0.0591	$0.0795	$0.0893	$0.1033	$0.1145	$0.1522
2	$0.0899		$0.0795	$0.0452	$0.0549	$0.0700	$0.0802	$0.1178
3	$0.0997		$0.0893	$0.0549	$0.0385	$0.0682	$0.0784	$0.1161
4	$0.1148		$0.1044	$0.0700	$0.0682	$0.0420	$0.0478	$0.0853
5	$0.1250		$0.1145	$0.0802	$0.0784	$0.0478	$0.0446	$0.0784
6	$0.1627		$0.1522	$0.1178	$0.1161	$0.0853	$0.0784	$0.0661

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

2/ The applicable fuel retention percentages are listed on Sheet No. 32, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Issued: April 19, 2010
Effective: April 19, 2010

Docket No. RP10-619-000
Accepted:

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0083		$0.0307	$0.0472	$0.0586	$0.0706	$0.0803	$0.0979
L		$0.0031						
1	$0.0111		$0.0217	$0.0392	$0.0478	$0.0593	$0.0725	$0.0849
2	$0.0472		$0.0232	$0.0029	$0.0074	$0.0157	$0.0283	$0.0403
3	$0.0586		$0.0478	$0.0074	$0.0006	$0.0227	$0.0334	$0.0462
4	$0.0706		$0.0548	$0.0231	$0.0280	$0.0077	$0.0131	$0.0259
5	$0.0803		$0.0725	$0.0283	$0.0334	$0.0130	$0.0128	$0.0187
6	$0.0979		$0.0849	$0.0403	$0.0462	$0.0243	$0.0115	$0.0056

Minimum
Commodity Rates 1/, 2/ 3/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0132		$0.0440	$0.0668	$0.0825	$0.0991	$0.1124	$0.1361
L		$0.0060						
1	$0.0170		$0.0316	$0.0558	$0.0676	$0.0835	$0.1017	$0.1182
2	$0.0668		$0.0337	$0.0057	$0.0119	$0.0234	$0.0407	$0.0566
3	$0.0825		$0.0676	$0.0119	$0.0025	$0.0330	$0.0478	$0.0648
4	$0.0991		$0.0773	$0.0336	$0.0403	$0.0123	$0.0198	$0.0368
5	$0.1124		$0.1017	$0.0407	$0.0478	$0.0196	$0.0194	$0.0269
6	$0.1361		$0.1182	$0.0566	$0.0648	$0.0346	$0.0169	$0.0088

Maximum
Commodity Rates 1/, 2/, 3/, 4/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0132		$0.0440	$0.0668	$0.0825	$0.0991	$0.1124	$0.1361
L		$0.0060						
1	$0.0170		$0.0316	$0.0558	$0.0676	$0.0835	$0.1017	$0.1182
2	$0.0668		$0.0337	$0.0057	$0.0119	$0.0234	$0.0407	$0.0566
3	$0.0825		$0.0676	$0.0119	$0.0025	$0.0330	$0.0478	$0.0648
4	$0.0991		$0.0773	$0.0336	$0.0403	$0.0123	$0.0198	$0.0368
5	$0.1124		$0.1017	$0.0407	$0.0478	$0.0196	$0.0194	$0.0269
6	$0.1361		$0.1182	$0.0566	$0.0648	$0.0346	$0.0169	$0.0088

Notes:

1/ includes a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions are listed on Sheet No. 32. For service that is rendered entirely by displacement, shipper shall render only the quantity of gas associated with Losses of 0.5%.

3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.

4/ Includes a per Dth charge for the Hurricane Surcharge Adjustment per Article XXXIX of the General Terms and Conditions and listed on Sheet No. 34.

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\,3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G.

Tennessee Gas Pipeline Company
FERC Gas Tariff
Sixth Revised Volume No. 1

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/					
Segment U	$9.65		$0.00	$9.65	
Segment 1	$1.33		$0.00	$1.33	
Segment 2	$8.08		$0.00	$8.08	
Segment 3	$5.07		$0.00	$5.07	
Segment 4	$5.54		$0.00	$5.54	
Commodity Rate 2/, 3/					
Segments U, 1, 2, 3 & 4		$0.0019		$\boxed{\$0.0019}$	6/
Extended Receipt and Delivery Rate 4/, 7/					
Segment U	$0.3173			$0.3173	5.52%
Segment 1	$0.0437			$0.0437	0.69%
Segment 2	$0.2656			$0.2656	0.59%
Segment 3	$0.1667			$0.1667	0.73%
Segment 4	$0.1821			$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 105.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

NET-284 RATE SCHEDULE (continued)

5. FUEL AND USE (continued)

Shipper	Transportation Quantity (Dth)	Segments U	1	2	3	4	Fuel and Use
Bay State (from Granite) - Pleasant St.	3,706				*	*	1.26%
Bay State (from Granite) - Agawam	6,068				*		0.96%
Boston Gas d/b/a National Grid	35,000				*	*	1.31%
Boston Gas d/b/a National Grid	8,600				*	*	1.31%
Barclays Bank PLC	14,010				*	*	1.23%
EnergyNorth Natural Gas, Inc. d/b/a National Grid	4,000				*	*	1.54%
Essex Gas Company d/b/a National Grid	2,000				*	*	1.44%
Iroquois Gas Transmission (Connecticut Natural, Yankee Gas)	37,000				*		0.68%
Lockport Energy Associates	13,184	*	*				6.21%
New York State Electric & Gas Corp	14,816	*	*				6.21%
Northern Utilities (from Granite) Pleasant St.	844				*	*	1.26%
Northern Utilities (from Granite) Agawam	1,382				*		0.96%
The Narragansett Electric Company d/b/a National Grid	1,000				*	*	1.25%
Yankee Gas Services Company (Wright)	9,000				*		1.07%
Total	150,610						

FUEL AND LOSS RETENTION PERCENTAGE (F&LR) 1/,2/,3/,4/

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.5%.
2/ for service that is rendered entirely by displacement, shipper shall render only the quantity of gas associated with Losses of 0.5%.
3/ The F&LR percentages listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ F&LR determined pursuant to Article XXXVII of the General Terms and Conditions.

RATE SCHEDULE NET 284 1/, 2/
==

Notes:

1/ The rates for service under Rate Schedule NET-284 shall be equal to the applicable rates for service under Rate Schedule FT-A in the Summary of Rates and Charges on Sheet Nos. 14 – 17.

2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions are listed on Sheet No. 32. For service rendered entirely by displacement, Shipper shall render only the quantity of gas assoicated with Losses of 0.5%.

Canadian Variable Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Commodity Rate	$CAD / GJ	$ 0.00922	Page 20
3	Delivery Pressure Commodity Rate	$CAD / GJ	$ -	
4	Variable Transportation Rate	$CAD / GJ	$ 0.00922	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.01	Page 22
6	Variable Transportation Rate	$US / GJ	$ 0.0093	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ 0.0098	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Commodity Rate	$CAD / GJ	$ 0.02275	Page 18
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ 0.03798	Page 19
13	Variable Transportation Rate	$CAD / GJ	$ 0.06073	Line 11 plus Line 12
14	$CAD to $US	Ratio	1.01	Page 22
15	Variable Transportation Rate	$US / GJ	$ 0.0613	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ 0.0647	Line 15 divided by Line 16

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Interim Tolls effective January 1, 2011

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Dawn*	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn*	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn*	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn*	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn*	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn*	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn*	Iroquois	10.82669	0.01413	0.3700	0.4070
8	Union Dawn*	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn*	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn*	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn*	East Hereford	16.76744	0.02275	0.5741	0.6315
12	Union Dawn*	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

TransCanada
In business to deliver

Transportation Tolls
Interim Tolls effective January 1, 2011

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	0.78572	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	1.96558	0.03798	0.10260

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Interim Tolls effective January 1, 2011

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union EDA	St. Clair	9.62739	0.01248	0.3290	0.3619
2	Union EDA	Dawn Export	9.27219	0.01196	0.3168	0.3485
3	Union EDA	Kirkwall	6.45997	0.00789	0.2203	0.2423
4	Union EDA	Niagara Falls	7.86854	0.00993	0.2686	0.2955
5	Union EDA	Chippawa	7.90416	0.00998	0.2699	0.2969
6	Union EDA	Iroquois	2.76146	0.00230	0.0931	0.1024
7	Union EDA	Cornwall	3.25751	0.00305	0.1102	0.1212
8	Union EDA	Napierville	5.57830	0.00642	0.1898	0.2088
9	Union EDA	Philipsburg	5.83975	0.00680	0.1988	0.2187
10	Union EDA	East Hereford	8.60815	0.01081	0.2938	0.3232
11	Union EDA	Welwyn	37.82076	0.05331	1.2967	1.4264
12	Union Parkway Belt	Empress	43.42151	0.06141	1.4890	1.6379
13	Union Parkway Belt	Transgas SSDA	37.00095	0.05172	1.2682	1.3950
14	Union Parkway Belt	Centram SSDA	34.30543	0.04819	1.1760	1.2936
15	Union Parkway Belt	Centram MDA	30.26186	0.04260	1.0375	1.1413
16	Union Parkway Belt	Centrat MDA	29.71379	0.04153	1.0184	1.1202
17	Union Parkway Belt	Union WDA	23.15789	0.03209	0.7935	0.8729
18	Union Parkway Belt	Nipigon WDA	20.24386	0.02779	0.6934	0.7627
19	Union Parkway Belt	Union NDA	8.93682	0.01154	0.3053	0.3358
20	Union Parkway Belt	Calstock NDA	15.31385	0.02064	0.5241	0.5765
21	Union Parkway Belt	Tunis NDA	11.43245	0.01501	0.3909	0.4300
22	Union Parkway Belt	GMIT NDA	8.53079	0.01075	0.2913	0.3204
23	Union Parkway Belt	Union SSMDA	13.53681	0.01806	0.4631	0.5094
24	Union Parkway Belt	Union NCDA	3.82527	0.00400	0.1298	0.1428
25	Union Parkway Belt	Union CDA	1.47153	0.00019	0.0486	0.0535
26	Union Parkway Belt	Enbridge CDA	2.22307	0.00159	0.0747	0.0822
27	Union Parkway Belt	Union EDA	5.89043	0.00706	0.2008	0.2209
28	Union Parkway Belt	Enbridge EDA	8.74334	0.01112	0.2986	0.3285
29	Union Parkway Belt	GMIT EDA	10.42379	0.01357	0.3563	0.3919
30	Union Parkway Belt	KPUC EDA	5.61602	0.00657	0.1912	0.2103
31	Union Parkway Belt	North Bay Junction	6.44312	0.00777	0.2196	0.2416
32	Union Parkway Belt	Enbridge SWDA	4.46784	0.00491	0.1518	0.1670
33	Union Parkway Belt	Union SWDA	4.77341	0.00526	0.1622	0.1784
34	Union Parkway Belt	Spruce	30.28333	0.04235	1.0380	1.1418
35	Union Parkway Belt	Emerson 1	28.16808	0.03928	0.9654	1.0619
36	Union Parkway Belt	Emerson 2	28.16808	0.03928	0.9654	1.0619
37	Union Parkway Belt	St. Clair	4.82304	0.00542	0.1640	0.1804
38	Union Parkway Belt	Dawn Export	4.46784	0.00491	0.1518	0.1670
39	Union Parkway Belt	Kirkwall	1.65562	0.00083	0.0552	0.0607
40	Union Parkway Belt	Niagara Falls	3.06195	0.00287	0.1036	0.1140
41	Union Parkway Belt	Chippawa	3.09758	0.00292	0.1047	0.1152
42	Union Parkway Belt	Iroquois	7.44492	0.00922	0.2540	0.2794
43	Union Parkway Belt	Cornwall	8.03325	0.01008	0.2742	0.3016
44	Union Parkway Belt	Napierville	10.36656	0.01346	0.3543	0.3897
45	Union Parkway Belt	Philipsburg	10.62875	0.01384	0.3632	0.3995
46	Union Parkway Belt	East Hereford	13.38567	0.01784	0.4579	0.5037
47	Union Parkway Belt	Welwyn	34.30543	0.04819	1.1760	1.2936
48	Union NCDA	Empress	42.31537	0.00000	1.3912	1.5303
49	Union NCDA	Transgas SSDA	35.76305	0.00000	1.1758	1.2934
50	Union NCDA	Centram SSDA	33.06977	0.00000	1.0872	1.1959
51	Union NCDA	Centram MDA	29.06033	0.04084	0.9962	1.0958
52	Union NCDA	Centrat MDA	27.24469	0.00000	0.8957	0.9853
53	Union NCDA	Union WDA	20.41646	0.00000	0.6712	0.7383
54	Union NCDA	Nipigon WDA	17.50243	0.00000	0.5754	0.6329
55	Union NCDA	Union NDA	6.20821	0.00755	0.2117	0.2329
56	Union NCDA	Calstock NDA	12.57243	0.00000	0.4133	0.4546
57	Union NCDA	Tunis NDA	8.69103	0.00000	0.2857	0.3143
58	Union NCDA	GMIT NDA	5.78937	0.00674	0.1970	0.2167
59	Union NCDA	Union SSMDA	16.27407	0.02206	0.5571	0.6128
60	Union NCDA	Union NCDA	1.08608	0.00000	0.0357	0.0393
61	Union NCDA	Union CDA	4.21072	0.00419	0.1426	0.1569
62	Union NCDA	Enbridge CDA	3.73926	0.00389	0.1268	0.1395
63	Union NCDA	Union EDA	7.20867	0.00900	0.2460	0.2706
64	Union NCDA	Enbridge EDA	9.39814	0.01213	0.3211	0.3532
65	Union NCDA	GMIT EDA	11.58255	0.01529	0.3961	0.4357
66	Union NCDA	KPUC EDA	6.96690	0.00856	0.2376	0.2614
67	Union NCDA	North Bay Junction	3.70393	0.00000	0.1218	0.1340
68	Union NCDA	Enbridge SWDA	7.20703	0.00891	0.2458	0.2704
69	Union NCDA	Union SWDA	7.51260	0.00927	0.2563	0.2819

Schedule "C"

UNION GAS LIMITED

M12 Monthly Transportation Fuel Ratios and Rates

Firm or Interruptible Transportation Commodity

Effective January 1, 2011

	VT1 Easterly to Parkway (TCPL) With Dawn Compression		VT1 Easterly to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression		VT3 Westerly to Kirkwall, Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.763	0.041	0.763	0.041	0.328	0.018
May	0.624	0.034	0.624	0.034	0.328	0.018
June	0.416	0.023	0.328	0.018	0.416	0.023
July	0.357	0.018	0.328	0.018	0.357	0.018
August	0.350	0.019	0.328	0.018	0.350	0.019
September	0.368	0.019	0.348	0.019	0.368	0.019
October	0.745	0.040	0.697	0.038	0.328	0.018
November	0.948	0.051	0.765	0.042	0.328	0.018
December	1.174	0.062	0.950	0.052	0.328	0.018
January	1.306	0.071	1.076	0.058	0.328	0.018
February	1.207	0.064	0.991	0.053	0.328	0.018
March	1.046	0.057	0.854	0.046	0.328	0.018

	M12-X Easterly Kirkwall to Parkway (TCPL)		M12-X Easterly Kirkwall to Lisgar, Parkway (Consumers)		M12-X Westerly to Kirkwall, Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.328	0.018	0.328	0.018	0.353	0.020
May	0.328	0.018	0.328	0.018	0.353	0.020
June	0.416	0.023	0.328	0.018	0.353	0.020
July	0.357	0.019	0.328	0.018	0.353	0.020
August	0.350	0.019	0.328	0.018	0.353	0.020
September	0.348	0.019	0.328	0.018	0.353	0.020
October	0.376	0.020	0.328	0.018	0.353	0.020
November	0.511	0.027	0.328	0.018	0.328	0.018
December	0.551	0.029	0.328	0.018	0.328	0.018
January	0.558	0.030	0.328	0.018	0.328	0.018
February	0.544	0.029	0.328	0.018	0.328	0.018
March	0.520	0.028	0.328	0.018	0.328	0.018

Regular page >>

Bank of Canada

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:
10-Year Currency Converter

Using rates for: 13 Jan 2011

Convert to and from Canadian dollars, using the latest noon rates.

Currency:	U.S. dollar
Amount:	1.00
Convert:	(•) from $Can ( ) to $Can
Use the:	(•) Nominal rate HELP ( ) Cash rate (4%) HELP
Answer:	1.01 CONVERT
Exchange rate:	1.0134

Summary:

On 13 Jan 2011, 1.00 Canadian dollar(s) = 1.01 U.S. dollar(s), at an exchange rate of 1.0134 (using nominal rate.)

Effective 1 January 2009, the euro replaces the Slovak koruna.

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

Why is the currency I'm looking for not listed here?

The Bank currently collects data for over 50 foreign currencies. These data are intended primarily for individuals with a research interest in foreign exchange markets and represent only a sampling of currencies.

More comprehensive currency converters include CanadianForex and OANDA.com.

Are the exchange rates shown here accepted by the Canada Revenue Agency?

Yes. The Agency accepts Bank of Canada exchange rates as the basis for calculations involving income

Historic TransCanada Fuel Loss Percentages

	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Last 12 Months	Last Nov - Mar	Last Apr - Oct
Union Dawn - Iroquois	0.69%	0.94%	1.00%	1.63%	1.41%	1.62%	1.60%	1.47%	1.36%	1.39%	1.35%	1.56%	1.34%	1.45%	1.25%
Union Dawn - East Hereford	0.00%	0.50%	0.49%	1.36%	1.14%	1.42%	1.31%	1.05%	1.01%	1.08%	1.03%	1.20%	0.97%	1.14%	0.84%
Empress - East Hereford	0.00%	2.01%	1.55%	3.84%	3.71%	4.43%	3.80%	2.78%	3.09%	3.43%	3.32%	3.23%	2.93%	3.47%	2.55%

INFORMATIONAL POSTINGS

- Capacity
- Gas Quality
- Index of Customers
- Notices
- Posted Imbalances
- Standards of Conduct
- Tariff
  - Title Sheet
  - Table of Contents
  - Preliminary Statement
  - Map
  - Currently Effective Rates
  - Rate Schedules
  - General Terms and Conditions
  - Form of Service Agreement
  - Entire Tariff
  - Sheet Index
- Vector - Canada Tariff
- Transactional Reporting
- Other
- Downloads
- Search
- Customer Activities
- Site Map

Previous Next

Vector Pipeline L.P.
FERC Gas Tariff — Eleventh Revised Sheet No. 20
Original Volume No. 1 — Superseding
Tenth Revised Sheet No. 20

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.2501	0.0000	$7.7745	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0019	0.0019	0.0019	0.0019
Usage and ACA Charge	0.0019	0.0019	0.0019	0.0019

Negotiated Rates:

The effective maximum negotiated charge for any negotiated rate transportation agreement is the charge agreed to by the parties, as set forth in the attached Tariff sheets.

Rate Schedule FT-L 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum

Historic Vector Fuel Loss Rates

Receipt	Delivery	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Last 12 Months
W-10 Storage	Dawn	0.32%	0.30%	0.33%	0.30%	0.30%	0.48%	0.31%	0.30%	0.30%	0.32%	0.33%	0.47%	0.34%
Alliance	W-10 Storage	0.95%	0.91%	0.99%	0.91%	0.91%	1.11%	0.91%	0.90%	0.89%	0.95%	0.99%	1.40%	0.99%
Alliance	Dawn	0.95%	0.91%	0.99%	0.91%	0.91%	1.11%	0.91%	0.90%	0.89%	0.95%	0.99%	1.40%	0.99%

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA					
Deliverability Rate	$2.02		$0.00	$2.02	
Space Rate	$0.0248		$0.0000	$0.0248	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	
Overrun Rate	$0.2427			$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA					
Deliverability Rate	$1.15		$0.00	$1.15	
Space Rate	$0.0185		$0.0000	$0.0185	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
Overrun Rate	$0.1380			$0.1380	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA			
Deliverability Rate	$2.81	$2.81 1/	
Space Rate	$0.0286	$0.0286 1/	
Injection Rate	$0.0073	$0.0073 3/	1.49%
Withdrawal Rate	$0.0073	$0.0073 3/	
Overrun Rate	$0.3372	$0.3372 3/	
FIRM STORAGE SERVICE (FS) - MARKET AREA			
Deliverability Rate	$1.89	$1.89 1/	
Space Rate	$0.0262	$0.0262 1/	
Injection Rate	$0.0204	$0.0204 3/	1.49%
Withdrawal Rate	$0.0204	$0.0204 3/	
Overrun Rate	$0.2268	$0.2268 3/	

1/ Includes a per Dth charge of $0.00 for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions.

2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions associated with Losses is equal to 0.5%.

3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.

EXHIBIT I

Rates:

Monthly Deliverability Rate: $ 2.4754 per Dth

Monthly Capacity Rate: $ 0.0238 per Dth

Injection Rate: $ 0.00 per Dth

Withdrawal Rate: $ 0.00 per Dth

Authorized Overrun Rate: $ 0.05 per Dth

Interruptible Rate: $ 0.05 per Dth

Service Parameters:

Maximum Storage Quantity (MSQ): 3,400,000 Dth

Maximum Daily Injection Quantity (MDIQ):

Inventory	MDIQ
April 1 through October 31	17,000 Dth/d Firm
November 1 through March 31	17,000 Dth/d Interruptible

Maximum Daily Withdrawal Quantity (MDWQ):

Inventory	MDWQ
November 1 through November 30	64,600 Dth/d Firm
December 1 through March 31	
Inventory ≥ 680,000 Dth	34,000 Dth/d Firm
Inventory ≥ 340,000 Dth and < 680,000 Dth	22,780 Dth/d Firm
Inventory ≥ 0 Dth and < 340,000 Dth	13,600 Dth/d Firm
April 1 through October 31	34,000Dth/d Interruptible

Primary Receipt Point(s): W-10 / Vector Interconnect

Secondary Receipt Point(s): W-10 / MichCon Interconnect

Primary Delivery Point(s): W-10 / Vector Interconnect

Secondary Delivery Point(s): W-10 / MichCon Interconnect

DTE Energy

Home | MichCon Storage & Transportation | MichCon Pipeline | DTE Gas Storage

- Our Services
- Notices
- Contact Us
- Forms
- Tariffs

DTE Gas Storage - Washington 10 Historic Fuel Rates

Effective Date	Injection	Withdrawal	Wheel From Hub to Interconnect
Apr 1, 2010	1.00%	0.40%	0.30%
Mar 10, 2010	1.00%	0.40%	0.45%
Mar 3, 2010	1.00%	0.40%	0.00%
Mar 1, 2010	1.00%	0.40%	0.45%
Nov 1, 2009	0.00%	0.40%	n/a
Apr 1, 2009	0.95%	0.00%	n/a
Nov 1, 2008	0.00%	0.55%	n/a
Apr 1, 2008	0.70%	0.50%	n/a
Nov 1, 2007	0.00%	0.70%	n/a
Apr 1, 2007	0.70%	0.00%	n/a
Dec 1, 2006	0.00%	0.30%	n/a
Apr 1, 2006	0.50%	0.00%	n/a
Nov 1, 2005	0.00%	0.50%	n/a
Apr 1, 2005	0.72%	0.00%	n/a
Nov 1, 2004	0.00%	0.50%	n/a
Apr 1, 2004	0.58%	0.00%	n/a

DTEEnergy.com | Privacy Policy | Terms of Use

Schedule 7

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc. Hedging Gains and Losses May 2011 through October 2011 As of 1/20/2011							
Description	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Season
Time Triggered NYMEX Contracts	14	0	0	0	0	9	23
Average Purchase Price	$ 4.712					$ 4.944	$ 4.803
Current NYMEX Price	$ 4.707					$ 4.869	$ 4.770
Hedging (Gains) or Losses - Allocate	$ 720	$ -	$ -	$ -	$ -	$ 6,740	$ 7,460

Schedule 8

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Summer 2011 vs. Summer 2010

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2010- 2011																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.0987	$119.76						$119.76								
	CGA 2	$1.0736		$161.04					$161.04								
	CGA 3	$1.1199			$209.42				$209.42								
	CGA 4	$1.1615				$218.36			$218.36								
	CGA 5	$1.1615					$192.81		$192.81								
	CGA 6	$1.1615						$153.32	$153.32								
	LDAC	$0.0454	$4.95	$6.81	$8.49	$8.54	$7.54	$5.99	$42.31								
Summer 2011																	
Customer Charge	units @	$ 9.50								$ 9.50	$9.50	$9.50	$9.50	$ 9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.6354								$57.19						$57.19	
	CGA 2	$0.6354									$34.95					$34.95	
	CGA 3	$0.6354										$19.06				$19.06	
	CGA 4	$0.6354											$19.06			$19.06	
	CGA 5	$0.6354												$26.69		$26.69	
	CGA 6	$0.6354													$45.11	$45.11	
	LDAC	$ 0.0456								$4.10	$2.51	$1.37	$1.37	$1.92	$3.24	$14.50	
		TOTAL	$172.36	$227.76	$288.88	$298.17	$265.04	$213.84	$1,466.05	$103.26	$68.96	$42.24	$42.24	$55.33	$84.64	$396.66	$1,862.71

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2009 - 2010																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.0980	$119.68						$119.68								
	CGA 2	$1.0980		$164.70					$164.70								
	CGA 3	$1.0218			$191.08				$191.08								
	CGA 4	$1.0758				$202.25			$202.25								
	CGA 5	$1.0758					$178.58		$178.58								
	CGA 6	$0.6693						$88.35	$88.35								
	LDAC	$ 0.0297	$3.24	$4.46	$5.55	$5.58	$4.93	$3.92	$27.68								
Summer 2010																	
Customer Charge	units @	$ 9.50								$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.6545								$58.91						$58.91	
	CGA 2	$0.5969									$32.83					$32.83	
	CGA 3	$0.7280										$21.84				$21.84	
	CGA 4	$0.7280											$21.84			$21.84	
	CGA 5	$0.7280												$30.58		$30.58	
	CGA 6	$0.7280													$51.69	$51.69	
	LDAC	$ 0.0297								$2.67	$1.63	$0.89	$0.89	$1.25	$2.11	$9.44	
		TOTAL	$170.57	$229.07	$267.60	$279.11	$248.21	$146.80	$1,341.35	$103.55	$65.97	$44.54	$44.54	$58.55	$90.09	$407.23	$1,748.58
		Change	$1.79	($1.31)	$21.28	$19.06	$16.83	$67.04	$124.70	($0.29)	$2.99	($2.30)	($2.30)	($3.22)	($5.45)	**($10.57)**	$114.14
		% Chg	1.05%	-0.57%	7.95%	6.83%	6.78%	45.67%	9.30%	-0.28%	4.54%	-5.17%	-5.17%	-5.50%	-6.05%	**-2.59%**	6.53%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 2,000 therms/year

Comparison of Summer 2011 vs. Summer 2010

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2010 - 2011																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3077	$23.08	$23.08	$23.08	$23.08	$23.08	$23.08	$138.47								
Over	75 units @	$0.2007	$23.68	$38.94	$44.76	$37.53	$31.91	$19.27	$196.08								
	CGA 1	$1.1231	$216.76						$216.76								
	CGA 2	$1.0980		$295.36					$295.36								
	CGA 3	$1.1443			$341.00				$341.00								
	CGA 4	$1.1859				$310.71			$310.71								
	CGA 5	$1.1859					$277.50		$277.50								
	CGA 6	$1.1859						$202.79	$202.79								
	LDAC	$0.0259	$5.00	$6.97	$7.72	$6.79	$6.06	$4.43	$36.96								
Summer 2011																	
Customer Charge	units @	$ 18.70								$ 18.70	$18.70	$18.70	$18.70	$ 18.70	$18.70	$112.20	
First	75 units @	$0.3077								$23.08	$23.08	$22.15	$22.15	$23.08	$23.08	$136.62	
Over	75 units @	$0.2007								$8.43	$1.20	$0.00	$0.00	$2.81	$13.45	$25.89	
	CGA 1	$0.6878								$80.47						$80.47	
	CGA 2	$0.6878									$55.71					$55.71	
	CGA 3	$0.6878										$49.52				$49.52	
	CGA 4	$0.6878											$49.52			$49.52	
	CGA 5	$0.6878												$61.21		$61.21	
	CGA 6	$0.6878													$97.67	$97.67	
	LDAC	$ 0.0166								$1.94	$1.34	$1.20	$1.20	$1.48	$2.36	$9.51	
		TOTAL	$287.22	$383.04	$435.25	$396.80	$357.25	$268.26	$2,127.83	$132.62	$100.04	$91.57	$91.57	$107.28	$155.25	$678.33	$2,806.16

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2009 - 2010																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3077	$23.08	$23.08	$23.08	$23.08	$23.08	$23.08	$138.47								
Over	75 units @	$0.2007	$23.68	$38.94	$44.76	$37.53	$31.91	$19.27	$196.08								
	CGA 1	$1.1058	$213.42						$213.42								
	CGA 2	$1.1058		$297.46					$297.46								
	CGA 3	$1.0296			$306.82				$306.82								
	CGA 4	$1.0836				$283.90			$283.90								
	CGA 5	$1.0836					$253.56		$253.56								
	CGA 6	$0.6771						$115.78	$115.78								
	LDAC	$ 0.0166	$3.20	$4.47	$4.95	$4.35	$3.88	$2.84	$23.69								
Summer 2010																	
Customer Charge	units @	$ 18.70								$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20	
First	75 units @	$0.3077								$23.08	$23.08	$22.15	$22.15	$23.08	$23.08	$136.62	
Over	75 units @	$0.2007								$8.43	$1.20	$0.00	$0.00	$2.81	$13.45	$25.89	
	CGA 1	$0.6905								$80.79						$80.79	
	CGA 2	$0.6329									$51.26					$51.26	
	CGA 3	$0.7640										$55.01				$55.01	
	CGA 4	$0.7640											$55.01			$55.01	
	CGA 5	$0.7640												$68.00		$68.00	
	CGA 6	$0.7640													$108.49	$108.49	
	LDAC	$ 0.0211								$2.47	$1.71	$1.52	$1.52	$1.88	$3.00	$12.09	
		TOTAL	$282.08	$382.64	$398.30	$367.56	$331.14	$179.67	$1,941.39	$133.46	$95.96	$97.38	$97.38	$114.46	$166.71	$705.35	$2,646.74
		Change	$5.13	$0.40	$36.95	$29.24	$26.11	$88.60	$186.44	($0.84)	$4.08	($5.81)	($5.81)	($7.18)	($11.46)	**($27.02)**	$159.42
		% Chg	1.82%	0.11%	9.28%	7.95%	7.89%	49.31%	9.60%	-0.63%	4.25%	-5.97%	-5.97%	-6.27%	-6.87%	**-3.83%**	6.02%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 21,023 therms/year

Comparison of Summer 2011 vs. Summer 2010

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2010 - 2011																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.1942	$301.59	$500.65	$634.06	$796.80	$660.67	$480.26	$3,374.03								
	CGA 1	$1.1231	$1,744.17						$1,744.17								
	CGA 2	$1.0980		$2,830.64					$2,830.64								
	CGA 3	$1.1443			$3,736.14				$3,736.14								
	CGA 4	$1.1859				$4,865.75			$4,865.75								
	CGA 5	$1.1859					$4,034.43		$4,034.43								
	CGA 6	$1.1859						$2,932.73	$2,932.73								
	LDAC	$0.0259	$40.22	$66.77	$84.56	$106.27	$88.11	$64.05	$449.99								
Summer 2011																	
Customer Charge	units @	$ 60.30								$ 60.30	$60.30	$60.30	$60.30	$ 60.30	$60.30	$361.80	
All	units @	$0.1124								$141.40	$78.79	$46.53	$23.94	$40.91	$78.57	$410.15	
	CGA 1	$0.6878								$865.25						$865.25	
	CGA 2	$0.6878									$482.15					$482.15	
	CGA 3	$0.6878										$284.75				$284.75	
	CGA 4	$0.6878											$146.50			$146.50	
	CGA 5	$0.6878												$250.36		$250.36	
	CGA 6	$0.6878													$480.77	$480.77	
	LDAC	$ 0.0166								$20.88	$11.64	$6.87	$3.54	$6.04	$11.60	$60.57	
		TOTAL	$2,146.29	$3,458.36	$4,515.07	$5,829.12	$4,843.51	$3,537.34	$24,329.69	$1,087.83	$632.88	$398.46	$234.28	$357.62	$631.24	$3,342.30	$27,671.99

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2009 - 2010																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.1942	$301.59	$500.65	$634.06	$796.80	$660.67	$480.26	$3,374.03								
	CGA 1	$1.1058	$1,717.31						$1,717.31								
	CGA 2	$1.1058		$2,850.75					$2,850.75								
	CGA 3	$1.0296			$3,361.64				$3,361.64								
	CGA 4	$1.0836				$4,446.01			$4,446.01								
	CGA 5	$1.0836					$3,686.41		$3,686.41								
	CGA 6	$0.6771						$1,674.47	$1,674.47								
	LDAC	$ 0.0166	$25.78	$42.79	$54.20	$68.11	$56.47	$41.05	$288.41								
Summer 2010																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
All	units @	$0.1124								$141.40	$78.79	$46.53	$23.94	$40.91	$78.57	$410.15	
	CGA 1	$0.6905								$868.65						$868.65	
	CGA 2	$0.6329									$443.66					$443.66	
	CGA 3	$0.7640										$316.30				$316.30	
	CGA 4	$0.7640											$162.73			$162.73	
	CGA 5	$0.7640												$278.10		$278.10	
	CGA 6	$0.7640													$534.04	$534.04	
	LDAC	$ 0.0211								$26.54	$14.79	$8.74	$4.49	$7.68	$14.75	$76.99	
		TOTAL	$2,104.98	$3,454.49	$4,110.21	$5,371.22	$4,463.85	$2,256.08	$21,760.83	$1,096.89	$597.55	$431.87	$251.47	$386.99	$687.65	$3,452.41	$25,213.24
		Change	$41.31	$3.87	$404.86	$457.89	$379.66	$1,281.26	$2,568.86	($9.06)	$35.33	($33.41)	($17.19)	($29.37)	($56.41)	**($110.11)**	$2,458.75
		% Chg	1.96%	0.11%	9.85%	8.52%	8.51%	56.79%	11.80%	-0.83%	5.91%	-7.74%	-6.84%	-7.59%	-8.20%	**-3.19%**	9.75%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 20,489 therms/year

Comparison of Summer 2011 vs. Summer 2010

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2010 - 2011																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.1862	$242.06	$242.06	$242.06	$242.06	$242.06	$242.06	$1,452.36								
Over	1,300 units @	$0.1467	$61.91	$115.31	$151.10	$151.54	$145.38	$83.91	$709.15								
	CGA 1	$0.9702	$1,670.68						$1,670.68								
	CGA 2	$0.9451		$1,971.48					$1,971.48								
	CGA 3	$0.9914			$2,309.96				$2,309.96								
	CGA 4	$1.0330				$2,409.99			$2,409.99								
	CGA 5	$1.0330					$2,366.60		$2,366.60								
	CGA 6	$1.0330						$1,933.78	$1,933.78								
	LDAC	$0.0259	$44.60	$54.03	$60.35	$60.42	$59.34	$48.48	$327.22								
Summer 2011																	
Customer Charge	units @	$ 60.30								$ 60.30	$60.30	$60.30	$60.30	$ 60.30	$60.30	$361.80	
First	1,000 units @	$0.1112								$111.20	$111.20	$111.20	$111.20	$111.20	$111.20	$667.20	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27	$14.82	$16.38	$25.27	$144.69	
	CGA 1	$0.5697								$860.25						$860.25	
	CGA 2	$0.5697									$782.77					$782.77	
	CGA 3	$0.5697										$710.42				$710.42	
	CGA 4	$0.5697											$677.94			$677.94	
	CGA 5	$0.5697												$689.34		$689.34	
	CGA 6	$0.5697													$754.28	$754.28	
	LDAC	$ 0.0166								$25.07	$22.81	$20.70	$19.75	$20.09	$21.98	$130.39	
		TOTAL	$2,079.55	$2,443.17	$2,823.77	$2,924.31	$2,873.68	$2,368.53	$15,513.02	$1,096.59	$1,006.25	$921.88	$884.02	$897.30	$973.03	$5,779.08	$21,292.10

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2009 - 2010																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.1862	$242.06	$242.06	$242.06	$242.06	$242.06	$242.06	$1,452.36								
Over	1,300 units @	$0.1467	$61.91	$115.31	$151.10	$151.54	$145.38	$83.91	$709.15								
	CGA 1	$1.0630	$1,830.49						$1,830.49								
	CGA 2	$1.0630		$2,217.42					$2,217.42								
	CGA 3	$0.9868			$2,299.24				$2,299.24								
	CGA 4	$1.0408				$2,428.19			$2,428.19								
	CGA 5	$1.0408					$2,384.47		$2,384.47								
	CGA 6	$0.6343						$1,187.41	$1,187.41								
	LDAC	$ 0.0211	$36.33	$44.01	$49.16	$49.23	$48.34	$39.50	$266.58								
Summer 2010																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
First	1,000 units @	$0.1112								$111.20	$111.20	$111.20	$111.20	$111.20	$111.20	$667.20	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27	$14.82	$16.38	$25.27	$144.69	
	CGA 1	$0.6075								$917.33						$917.33	
	CGA 2	$0.5499									$755.56					$755.56	
	CGA 3	$0.6810										$849.21				$849.21	
	CGA 4	$0.6810											$810.39			$810.39	
	CGA 5	$0.6810												$824.01		$824.01	
	CGA 6	$0.6810													$901.64	$901.64	
	LDAC	$ 0.0211								$31.86	$28.99	$26.31	$25.11	$25.53	$27.94	$165.74	
		TOTAL	$2,231.09	$2,679.10	$2,801.87	$2,931.31	$2,880.55	$1,613.18	$15,137.10	$1,160.47	$985.23	$1,066.28	$1,021.82	$1,037.42	$1,126.35	$6,397.57	$21,534.67
		Change	($151.54)	($235.93)	$21.90	($7.00)	($6.87)	$755.35	$375.92	($63.87)	$21.02	($144.40)	($137.80)	($140.12)	($153.32)	**($618.49)**	($242.57)
		% Chg	-6.79%	-8.81%	0.78%	-0.24%	-0.24%	46.82%	2.48%	-5.50%	2.13%	-13.54%	-13.49%	-13.51%	-13.61%	**-9.67%**	-1.13%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2011 vs. Actual Summer 2010

Residential Heating	Summer 2010	Summer 2011
Customer Charge	$9.50	$9.50
First 50 Therms	$0.4102	$0.4102
Over 50 therms	$0.2990	$0.2990
LDAC	$0.0297	$0.0456
CGA	$0.6845	$0.6354

	Usage (Therms)	Summer 2010 Bill Amount	Summer 2011 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$15.12	$14.96	($0.17)	-1.1%	$0.00	0.0%	($0.25)	-1.7%	$0.08	0.5%
	10	$20.74	$20.41	($0.33)	-1.6%	$0.00	0.0%	($0.49)	-2.4%	$0.16	0.8%
	20	$31.99	$31.32	($0.66)	-2.1%	$0.00	0.0%	($0.98)	-3.1%	$0.32	1.0%
	25	$37.61	$36.78	($0.83)	-2.2%	$0.00	0.0%	($1.23)	-3.3%	$0.40	1.1%
	30	$43.23	$42.24	($1.00)	-2.3%	$0.00	0.0%	($1.47)	-3.4%	$0.48	1.1%
	45	$60.10	$58.60	($1.49)	-2.5%	$0.00	0.0%	($2.21)	-3.7%	$0.72	1.2%
Average Monthly	50	$65.72	$64.06	($1.66)	-2.5%	$0.00	0.0%	($2.46)	-3.7%	$0.80	1.2%
	75	$91.05	$88.56	($2.49)	-2.7%	$0.00	0.0%	($3.68)	-4.0%	$1.19	1.3%
	125	$141.71	$137.56	($4.15)	-2.9%	$0.00	0.0%	($6.14)	-4.3%	$1.99	1.4%
	150	$167.04	$162.06	($4.98)	-3.0%	$0.00	0.0%	($7.37)	-4.4%	$2.39	1.4%
	200	$217.70	$211.06	($6.64)	-3.1%	$0.00	0.0%	($9.82)	-4.5%	$3.18	1.5%

Schedule 9

Unitil
Northern Utilities, Inc.

Northern Utilities New Hampshire Division
Period Covered: May 1, 2011 - October 31, 2011
Variance Analysis

		2010 Summer (6 months actual)			Forecast Summer 2011 (6 months proposed)		
1	Therm Sales	6,609,210			7,400,642		
2				EFFECT			EFFECT
3		THERM		ON COST	THERM		ON COST
4		SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS
5							
6	Demand Charges		$1,058,022	$ 0.1601		$1,063,217	$ 0.1437
7							
8	Purchased Gas		3,333,201	0.5043		3,307,415	0.4469
9							
10	Storage & Peaking Gas		34,324	0.0052		25,185	0.0034
11							
12	Hedging (Gain)/Loss		527,641	0.0798		93,792	0.0127
13							
14							
15	Total Volumes and Cost	$ -	$4,953,188	$ 0.7494	$ -	$4,489,610	$ 0.6067
16							
17	Prior Period Balance		$91,535	$ 0.0138		$ 124,276	$ 0.0168
18	NHPUC Consultant Costs					$ 28,990	$ 0.0039
19	Interest		$ (6,272)	$(0.0009)		2,579	$ 0.0003
20	Refunds from Suppliers		-	$ -		-	$ -
21							
22	Prior Period Adjustment						
23	Interruptible Sales Margin		-	$ -		-	$ -
24	Capacity Release						
25	Working Capital Allowance		(7,494)	$(0.0011)		1,036	$ 0.0001
26	Bad Debt Allowance		3,159	$ 0.0005		24,057	$ 0.0033
27	Fuel Inventory Financing						
28	Local Production and Storage					-	$ -
29	Misc Overhead		28,452	$ 0.0043		31,261	$ 0.0042
30							
31	Total Anticipated Indirect Cost of Gas		$109,380	$ 0.0165		212,198	$ 0.0287
32	Total Adjusted Cost	-	5,062,568	$ 0.7660		4,701,808	$ 0.6353

Schedule 10

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

Base Capacity Costs

LN	BASE SENDOUT BY CLASS	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
2	**Total Therms**								
3	Res Heat	398,955	386,086	398,955	371,089	386,086	398,955	2,340,127	Schedule 10B, LN 52
4	Res General	15,958	15,443	13,670	15,958	15,443	15,958	92,431	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	113,572	109,908	95,493	113,572	109,908	113,572	656,026	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	66,910	64,751	45,740	66,910	64,751	66,910	375,972	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	146,213	141,497	129,896	146,213	141,497	146,213	851,530	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	122,197	118,256	89,387	122,197	118,256	122,197	692,490	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	22,076	21,364	22,076	22,018	21,364	22,076	130,975	Schedule 10B, LN 58
10	G42 High Annual-High Winter	11,693	11,315	11,693	11,498	11,315	11,693	69,207	Schedule 10B, LN 59
11	Total Firm Sales	897,575	868,621	806,910	869,455	868,621	897,575	5,208,758	Sum LN 3 : LN 10
12									
13	**% of Total**								
14	Res Heat	44.45%	44.45%	49.44%	42.68%	44.45%	44.45%		LN 3 / LN 11
15	Res General	1.78%	1.78%	1.69%	1.84%	1.78%	1.78%		LN 4 / LN 11
16	G50 Low Annual-Low Winter	12.65%	12.65%	11.83%	13.06%	12.65%	12.65%		LN 5 / LN 11
17	G40 Low Annual-High Winter	7.45%	7.45%	5.67%	7.70%	7.45%	7.45%		LN 6 / LN 11
18	G51 Med Annual-Low Winter	16.29%	16.29%	16.10%	16.82%	16.29%	16.29%		LN 7 / LN 11
19	G41 Med Annual-High Winter	13.61%	13.61%	11.08%	14.05%	13.61%	13.61%		LN 8 / LN 11
20	G52 High Annual-Low Winter	2.46%	2.46%	2.74%	2.53%	2.46%	2.46%		LN 9 / LN 11
21	G42 High Annual-High Winter	1.30%	1.30%	1.45%	1.32%	1.30%	1.30%		LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		LN 11 / LN 11
23									
24	**PIPELINE BASE DEMAND COSTS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 343,114	Schedule 1A, LN 69
26	Res Heat	$ 25,418	$ 25,418	$ 28,274	$ 24,407	$ 25,418	$ 25,418	$ 154,353	LN 25 * LN 14
27	Res General	$ 1,017	$ 1,017	$ 969	$ 1,050	$ 1,017	$ 1,017	$ 6,085	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 7,236	$ 7,236	$ 6,768	$ 7,470	$ 7,236	$ 7,236	$ 43,181	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 4,263	$ 4,263	$ 3,242	$ 4,401	$ 4,263	$ 4,263	$ 24,694	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 9,315	$ 9,315	$ 9,206	$ 9,617	$ 9,315	$ 9,315	$ 56,084	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 7,785	$ 7,785	$ 6,335	$ 8,037	$ 7,785	$ 7,785	$ 45,513	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 1,407	$ 1,407	$ 1,565	$ 1,448	$ 1,407	$ 1,407	$ 8,639	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 745	$ 745	$ 829	$ 756	$ 745	$ 745	$ 4,565	LN 25 * LN 21
34									
35	Residential	$ 26,435	$ 26,435	$ 29,243	$ 25,457	$ 26,435	$ 26,435	$ 160,438	LN 26 + LN 27
36	SALES HLF CLASSES	$ 17,958	$ 17,958	$ 17,538	$ 18,535	$ 17,958	$ 17,958	$ 107,904	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 12,793	$ 12,793	$ 10,405	$ 13,194	$ 12,793	$ 12,793	$ 74,772	LN 29 + LN 31 + LN 33
38									

Remaining Capacity Costs

LN		Column A Design Day Demand (MMBtu)	Column B Avg Daily Base Use Load (MMBtu)	Column C Remaining Design Day Demand (MMBtu)	Column D % of Total Remaining Design Day Demand	
39						
40	Res Heat	16,366	1,404	14,962	46.95%	Company Analysis
41	Res General	214	56	158	0.50%	Company Analysis
42	G50 Low Annual-Low Winter	880	346	534	1.67%	Company Analysis
43	G40 Low Annual-High Winter	7,688	263	7,425	23.30%	Company Analysis
44	G51 Med Annual-Low Winter	1,388	492	896	2.81%	Company Analysis
45	G41 Med Annual-High Winter	7,566	443	7,123	22.35%	Company Analysis
46	G52 High Annual-Low Winter	42	24	17	0.05%	Company Analysis
47	G42 High Annual-High Winter	846	94	753	2.36%	Company Analysis
48	TOTAL	34,989	3,122	31,868	100.00%	Sum LN 40 : LN 47
49						

50 **REMAINING PIPELINE DEMAND**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
51									
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 26,253	$ 5,345	$ 695	$ 2,382	$ 8,378	$ 32,871	$ 75,925	Schedule 1A, LN 70
53									
54	Res Heat	$ 12,326	$ 2,510	$ 326	$ 1,119	$ 3,933	$ 15,433	$ 35,647	LN 40 Col D * LN 52
55	Res General	$ 130	$ 27	$ 3	$ 12	$ 42	$ 163	$ 377	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 440	$ 90	$ 12	$ 40	$ 140	$ 550	$ 1,271	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 6,117	$ 1,245	$ 162	$ 555	$ 1,952	$ 7,659	$ 17,690	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 738	$ 150	$ 20	$ 67	$ 235	$ 924	$ 2,134	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 5,868	$ 1,195	$ 155	$ 532	$ 1,873	$ 7,347	$ 16,970	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 14	$ 3	$ 0	$ 1	$ 5	$ 18	$ 42	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 620	$ 126	$ 16	$ 56	$ 198	$ 776	$ 1,793	LN 47 Col D * LN 52
62	TOTAL	$ 26,253	$ 5,345	$ 695	$ 2,382	$ 8,378	$ 32,871	$ 75,925	Sum LN 54 : LN 61
63									
64	Residential	$ 12,456	$ 2,536	$ 330	$ 1,130	$ 3,975	$ 15,596	$ 36,024	LN 54 + LN 55
65	SALES HLF CLASSES	$ 1,192	$ 243	$ 32	$ 108	$ 380	$ 1,492	$ 3,447	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 12,605	$ 2,566	$ 334	$ 1,144	$ 4,022	$ 15,783	$ 36,454	LN 57 + LN 59 + LN 61
67									

68 **PEAKING AND STORAGE DEMAND**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
69									
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 222,743	$ 45,349	$ 5,899	$ 20,212	$ 71,080	$ 278,895	$ 644,179	Schedule 1A, LN 73
71									
72	Res Heat	$ 104,579	$ 21,292	$ 2,770	$ 9,490	$ 33,372	$ 130,943	$ 302,446	LN 40 Col D * LN 70
73	Res General	$ 1,105	$ 225	$ 29	$ 100	$ 353	$ 1,384	$ 3,197	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 3,730	$ 759	$ 99	$ 338	$ 1,190	$ 4,670	$ 10,788	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 51,899	$ 10,566	$ 1,374	$ 4,710	$ 16,562	$ 64,983	$ 150,094	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 6,260	$ 1,275	$ 166	$ 568	$ 1,998	$ 7,839	$ 18,105	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 49,787	$ 10,136	$ 1,319	$ 4,518	$ 15,888	$ 62,338	$ 143,985	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 122	$ 25	$ 3	$ 11	$ 39	$ 153	$ 353	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 5,260	$ 1,071	$ 139	$ 477	$ 1,678	$ 6,586	$ 15,211	LN 47 Col D * LN 70
80	TOTAL	$ 222,743	$ 45,349	$ 5,899	$ 20,212	$ 71,080	$ 278,895	$ 644,179	Sum LN 72 : LN 79
81									
82	Residential	$ 105,685	$ 21,517	$ 2,799	$ 9,590	$ 33,725	$ 132,327	$ 305,643	LN 72 + LN 73
83	SALES HLF CLASSES	$ 10,113	$ 2,059	$ 268	$ 918	$ 3,227	$ 12,662	$ 29,246	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 106,946	$ 21,774	$ 2,832	$ 9,705	$ 34,128	$ 133,906	$ 309,291	LN 75 + LN 77 + LN 79
85									

86 **CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
87									
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 76
89									
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 90 : LN 97
99									
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
105									
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 77
107									
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117									
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115

121

122 **REMAINING RE-ENTRY FEE CREDIT**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
123		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
124	NH DIVISION - RE-ENTRY FEE CREDITS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 78
125									
126	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 124
127	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 124
128	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 124
129	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 124
130	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 124
131	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 124
132	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 124
133	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 124
134	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 126 : LN 133
135									
136	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 126 + LN 127
137	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 128 + LN 130 + LN 132
138	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 129 + LN 131 + LN 133

139

140 **TOTAL NON-BASE CAPACITY COSTS**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
141		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
142	Res Heat	$ 116,905	$ 23,801	$ 3,096	$ 10,608	$ 37,306	$ 146,376	$ 338,093	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 1,236	$ 252	$ 33	$ 112	$ 394	$ 1,547	$ 3,574	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 4,170	$ 849	$ 110	$ 378	$ 1,331	$ 5,221	$ 12,059	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 58,016	$ 11,812	$ 1,536	$ 5,265	$ 18,514	$ 72,642	$ 167,785	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 6,998	$ 1,425	$ 185	$ 635	$ 2,233	$ 8,762	$ 20,239	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 55,655	$ 11,331	$ 1,474	$ 5,050	$ 17,760	$ 69,685	$ 160,956	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 136	$ 28	$ 4	$ 12	$ 44	$ 171	$ 394	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 5,880	$ 1,197	$ 156	$ 534	$ 1,876	$ 7,362	$ 17,004	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 248,996	$ 50,694	$ 6,594	$ 22,595	$ 79,457	$ 311,766	$ 720,103	Sum LN 142 : LN 149
151									
152	Residential	$ 118,141	$ 24,053	$ 3,129	$ 10,721	$ 37,700	$ 147,923	$ 341,666	LN 142 + LN 143
153	SALES HLF CLASSES	$ 11,304	$ 2,302	$ 299	$ 1,026	$ 3,607	$ 14,154	$ 32,693	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 119,551	$ 24,340	$ 3,166	$ 10,848	$ 38,150	$ 149,689	$ 345,744	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
157		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
158	Res Heat	$ 142,323	$ 49,219	$ 31,370	$ 35,016	$ 62,724	$ 171,794	$ 492,445	LN 142 + LN 26
159	Res General	$ 2,252	$ 1,268	$ 1,002	$ 1,162	$ 1,411	$ 2,564	$ 9,659	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 11,406	$ 8,085	$ 6,878	$ 7,848	$ 8,566	$ 12,457	$ 55,240	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 62,279	$ 16,075	$ 4,778	$ 9,665	$ 22,777	$ 76,905	$ 192,479	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 16,314	$ 10,740	$ 9,391	$ 10,252	$ 11,549	$ 18,078	$ 76,323	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 63,440	$ 19,116	$ 7,809	$ 13,087	$ 25,545	$ 77,471	$ 206,469	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,543	$ 1,434	$ 1,568	$ 1,461	$ 1,450	$ 1,577	$ 9,033	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 6,625	$ 1,942	$ 984	$ 1,290	$ 2,621	$ 8,107	$ 21,569	LN 149 + LN 33
166	TOTAL	$ 306,182	$ 107,880	$ 63,780	$ 79,780	$ 136,643	$ 368,952	$ 1,063,217	Sum LN 158 : LN 165
167									
168	Residential	$ 144,576	$ 50,488	$ 32,371	$ 36,177	$ 64,135	$ 174,358	$ 502,104	LN 158 + LN 159
169	SALES HLF CLASSES	$ 29,262	$ 20,259	$ 17,837	$ 19,560	$ 21,565	$ 32,112	$ 140,596	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 132,344	$ 37,133	$ 13,571	$ 24,043	$ 50,943	$ 162,482	$ 420,516	LN 161 + LN 163 + LN 165
171									
172	% ALLOCATION BETWEEN SALES HLF AND LLF								
173	SALES HLF CLASSES							25%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES							75%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2010 - 2011 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Normal Winter	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	SUMMER
1	Res Heat	762,968	434,222	422,065	366,573	450,203	725,465	15,976,924	3,161,497
2	Res General	23,482	19,501	13,518	18,024	17,160	21,509	333,007	113,194
3	**Total Residential**	**786,450**	**453,723**	**435,582**	**384,597**	**467,364**	**746,974**	**16,309,931**	**3,274,690**
4	G50 Low Annual-Low Winter	131,168	114,357	94,429	130,049	124,994	130,997	1,665,440	725,994
5	G40 Low Annual-High Winter	266,566	121,198	45,230	87,008	117,998	235,683	7,128,120	873,682
6	G51 Med Annual-Low Winter	166,540	146,299	128,448	160,553	160,414	204,208	2,368,685	966,463
7	G41 Med Annual-High Winter	255,066	175,461	88,390	153,122	220,544	417,681	6,950,395	1,310,264
8	G52 High Annual-Low Winter	24,909	22,891	21,888	21,750	23,006	27,193	202,215	141,638
9	G42 High Annual-High Winter	14,486	12,751	11,755	11,358	22,564	34,997	804,805	107,911
10	**Total C&I**	**858,735**	**592,957**	**390,140**	**563,840**	**669,520**	**1,050,760**	**19,119,661**	**4,125,952**
11	**Total Sales**	**1,645,185**	**1,046,679**	**825,723**	**948,437**	**1,136,884**	**1,797,734**	**35,429,591**	**7,400,642**
12									
13	Residential Heat & Non Heat	786,450	453,723	435,582	384,597	467,364	746,974	16,309,931	3,274,690
14	SALES HLF CLASSES	322,617	283,547	244,765	312,352	308,414	362,399	4,236,340	1,834,095
15	SALES LLF CLASSES	536,118	309,409	145,375	251,488	361,106	688,360	14,883,320	2,291,857
16	**Total Firm Sales**	**1,645,185**	**1,046,679**	**825,723**	**948,437**	**1,136,884**	**1,797,734**	**35,429,591**	**7,400,642**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)								
20	Normal Winter	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**TOTAL**	**SUMMER**
21	Res Heat	770,794	439,392	426,822	371,089	455,845	733,724	16,149,760	3,197,665
22	Res General	23,723	19,733	13,670	18,246	17,375	21,754	336,661	114,501
23	G50 Low Annual-Low Winter	132,514	115,718	95,493	131,651	126,560	132,489	1,683,931	734,425
24	G40 Low Annual-High Winter	269,300	122,640	45,740	88,080	119,477	238,366	7,204,555	883,602
25	G51 Med Annual-Low Winter	168,248	148,041	129,896	162,531	162,424	206,533	2,394,963	977,673
26	G41 Med Annual-High Winter	257,682	177,550	89,387	155,008	223,308	422,436	7,026,040	1,325,370
27	G52 High Annual-Low Winter	25,165	23,164	22,135	22,018	23,295	27,503	204,505	143,279
28	G42 High Annual-High Winter	14,635	12,902	11,887	11,498	22,847	35,395	813,584	109,165
29	**Subtotal**								
30	Residential	794,517	459,124	440,492	389,335	473,220	755,478	16,486,421	3,312,166
31	SALES HLF CLASSES	325,926	286,923	247,524	316,199	312,279	366,525	4,283,399	1,855,376
32	SALES LLF CLASSES	541,617	313,093	147,014	254,586	365,631	696,197	15,044,180	2,318,137
33	**Total Firm Sales**	1,662,060	1,059,140	835,030	960,120	1,151,130	1,818,200	35,814,000	7,485,680

Northern Utilities - NEW HAMPSHIRE DIVISION
2010 - 2011 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Firm Sales	
1	Res Heat	Company Analysis
2	Res General	Company Analysis
3	**Total Residential**	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	Company Analysis
5	G40 Low Annual-High Winter	Company Analysis
6	G51 Med Annual-Low Winter	Company Analysis
7	G41 Med Annual-High Winter	Company Analysis
8	G52 High Annual-Low Winter	Company Analysis
9	G42 High Annual-High Winter	Company Analysis
10	**Total C&I**	Sum LN 4 : LN 9
11	**Total Sales**	LN 3 + LN 10
12		
13	Residential Heat & Non Heat	LN 3
14	SALES HLF CLASSES	LN 4 + LN 6 + LN 8
15	SALES LLF CLASSES	LN 5 + LN 7 + LN 9
16	**Total Firm Sales**	Sum LN 13 : LN 15
17		
18	**ESTIMATED SENDOUT BY CLASS - Therms**	
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)	
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Company Use, LAUF, BTU) x 10
22	Res General	LN 2 x Adj factor (Company Use, LAUF, BTU) x 10
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Company Use, LAUF, BTU) x 10
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Company Use, LAUF, BTU) x 10
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Company Use, LAUF, BTU) x 10
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Company Use, LAUF, BTU) x 10
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Company Use, LAUF, BTU) x 10
28	G42 High Annual-High Winter	LN 9 x Adj factor (Company Use, LAUF, BTU) x 10
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	12,870
37	Res General	515
38	G50 Low Annual-Low Winter	3,664
39	G40 Low Annual-High Winter	2,158
40	G51 Med Annual-Low Winter	4,717
41	G41 Med Annual-High Winter	3,942
42	G52 High Annual-Low Winter	712
43	G42 High Annual-High Winter	377
44	**Subtotal**	-
45	Residential	13,384
46	SALES HLF CLASSES	9,092
47	SALES LLF CLASSES	6,477
48	**Total Firm Sales**	**28,954**

49	**BASE SENDOUT BY CLASS - Therms**								
50	Days per Month	31	30	31	31	30	31		
51		**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**TOTAL**	**SUMMER**
52	Res Heat	398,955	386,086	398,955	371,089	386,086	398,955	4,669,512	2,340,127
53	Res General	15,958	15,443	13,670	15,958	15,443	15,958	185,605	92,431
54	G50 Low Annual-Low Winter	113,572	109,908	95,493	113,572	109,908	113,572	1,319,141	656,026
55	G40 Low Annual-High Winter	66,910	64,751	45,740	66,910	64,751	66,910	766,639	375,972
56	G51 Med Annual-Low Winter	146,213	141,497	129,896	146,213	141,497	146,213	1,705,228	851,530
57	G41 Med Annual-High Winter	122,197	118,256	89,387	122,197	118,256	122,197	1,405,965	692,490
58	G52 High Annual-Low Winter	22,076	21,364	22,076	22,018	21,364	22,076	192,201	130,975
59	G42 High Annual-High Winter	11,693	11,315	11,693	11,498	11,315	11,693	137,477	69,207
60	**Subtotal**								
61	Residential	414,913	401,529	412,626	387,047	401,529	414,913	4,855,117	2,432,558
62	SALES HLF CLASSES	281,862	272,769	247,466	281,803	272,769	281,862	3,216,570	1,638,531
63	SALES LLF CLASSES	200,800	194,322	146,819	200,605	194,322	200,800	2,310,081	1,137,669
64	**Total Firm Sales**	897,575	868,621	806,910	869,455	868,621	897,575	10,381,767	5,208,758
65									
66	**REMAINING SENDOUT BY CLASS - Therms**								
67		**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**TOTAL**	**SUMMER**
68	Res Heat	371,839	53,306	27,867	-	69,759	334,768	11,480,248	857,538
69	Res General	7,764	4,289	-	2,288	1,932	5,796	151,056	22,070
70	G50 Low Annual-Low Winter	18,942	5,810	-	18,079	16,651	18,917	364,790	78,398
71	G40 Low Annual-High Winter	202,390	57,889	-	21,170	54,725	171,456	6,437,916	507,630
72	G51 Med Annual-Low Winter	22,035	6,544	-	16,317	20,927	60,320	689,735	126,143
73	G41 Med Annual-High Winter	135,485	59,294	-	32,811	105,052	300,238	5,620,075	632,880
74	G52 High Annual-Low Winter	3,089	1,800	58	-	1,931	5,427	12,304	12,304
75	G42 High Annual-High Winter	2,942	1,587	195	-	11,532	23,703	676,108	39,958
76	**Subtotal**								
77	Residential	379,603	57,595	27,867	2,288	71,691	340,564	11,631,304	879,608
78	SALES HLF CLASSES	44,065	14,154	58	34,396	39,509	84,663	1,066,829	216,845
79	SALES LLF CLASSES	340,817	118,770	195	53,981	171,309	495,397	12,734,099	1,180,469
80	**Total Firm Sales**	764,485	190,519	28,120	90,665	282,509	920,625	25,432,233	2,276,922

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	DAILY BASE GAS ENTITLEMENT - Therms/day	
36	Res Heat	Avg (LN 21 Jul : LN 21 Aug) / 31 days
37	Res General	Avg (LN 22 Jul : LN 22 Aug) / 31 days
38	G50 Low Annual-Low Winter	Avg (LN 23 Jul : LN 23 Aug) / 31 days
39	G40 Low Annual-High Winter	Avg (LN 24 Jul : LN 24 Aug) / 31 days
40	G51 Med Annual-Low Winter	Avg (LN 25 Jul : LN 25 Aug) / 31 days
41	G41 Med Annual-High Winter	Avg (LN 26 Jul : LN 26 Aug) / 31 days
42	G52 High Annual-Low Winter	Avg (LN 27 Jul : LN 27 Aug) / 31 days
43	G42 High Annual-High Winter	Avg (LN 28 Jul : LN 28 Aug) / 31 days
44	**Subtotal**	
45	Residential	LN 36 + LN 37
46	SALES HLF CLASSES	LN 38 + LN 40 + LN 42
47	SALES LLF CLASSES	LN 39 + LN 41 + LN 43
48	**Total Firm Sales**	Sum LN 45 : LN 47
49	**BASE SENDOUT BY CLASS - Therms**	
50	Days per Month	
51		
52	Res Heat	MIN(LN 36 * LN 50, LN 21)
53	Res General	MIN(LN 37 * LN 50, LN 22)
54	G50 Low Annual-Low Winter	MIN(LN 38 * LN 50, LN 23)
55	G40 Low Annual-High Winter	MIN(LN 39 * LN 50, LN 24)
56	G51 Med Annual-Low Winter	MIN(LN 40 * LN 50, LN 25)
57	G41 Med Annual-High Winter	MIN(LN 41 * LN 50, LN 26)
58	G52 High Annual-Low Winter	MIN(LN 42 * LN 50, LN 27)
59	G42 High Annual-High Winter	MIN(LN 43 * LN 50, LN 28)
60	**Subtotal**	
61	Residential	LN 52 + LN 53
62	SALES HLF CLASSES	LN 54 + LN 56 + LN 58
63	SALES LLF CLASSES	LN 55 + LN 57 + LN 59
64	**Total Firm Sales**	Sum LN 61 : LN 63
65		
66	REMAINING SENDOUT BY CLASS - Therms	
67		
68	Res Heat	LN 21 - LN 52
69	Res General	LN 22 - LN 53
70	G50 Low Annual-Low Winter	LN 23 - LN 54
71	G40 Low Annual-High Winter	LN 24 - LN 55
72	G51 Med Annual-Low Winter	LN 25 - LN 56
73	G41 Med Annual-High Winter	LN 26 - LN 57
74	G52 High Annual-Low Winter	LN 27 - LN 58
75	G42 High Annual-High Winter	LN 28 - LN 59
76	**Subtotal**	
77	Residential	LN 68 + LN 69
78	SALES HLF CLASSES	LN 70 + LN 72 + LN 74
79	SALES LLF CLASSES	LN 71 + LN 73 + LN 75
80	**Total Firm Sales**	Sum LN 77 : LN 79

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Total Division Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	429,234	419,968	9,267	2.2%	5,386	3,880	437,655	-8,420	-1.9%	13,375	-21,795
Jun	349,143	332,756	16,388	4.9%	4,237	12,151	317,236	31,907	10.1%	10,730	21,177
Jul	284,277	280,688	3,589	1.3%	4,452	-862	279,336	4,941	1.8%	7,374	-2,433
Aug	281,167	286,046	-4,879	-1.7%	4,731	-9,610	268,980	12,187	4.5%	7,084	5,103
Sep	300,274	300,569	-294	-0.1%	4,464	-4,758	284,834	15,440	5.4%	7,528	7,912
Oct	376,496	371,838	4,658	1.3%	9,798	-5,140	362,059	14,438	4.0%	9,435	5,003
Off-Peak	2,020,593	1,991,863	28,729	1.4%	32,905	-4,176	1,950,100	70,492	3.6%	55,112	15,380

Note 1 Company Forecast
Note 2 Pages 2 - 4; Sum of Column 2 of Billed Deliveries table. Actual Data is weather normalized.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Pages 2 - 4; Sum of Column 7 of Billed Deliveries Table. Actual Data provided is weather normalized.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	28,722	28,358	364	1.3%	27,870	852	3.1%
Jun	28,693	28,332	361	1.3%	27,754	939	3.4%
Jul	28,593	28,147	446	1.6%	27,858	735	2.6%
Aug	28,543	28,079	464	1.7%	27,811	732	2.6%
Sep	28,523	28,106	417	1.5%	27,789	734	2.6%
Oct	28,917	28,175	742	2.6%	28,183	734	2.6%
Off-Peak	28,665	28,200	466	1.7%	27,878	788	2.8%

Note 1 Company Forecast
Note 2 Actual Data. Page 2 - 4; Sum of Column 2 of Meter Counts table.
Note 3 Actual Data. Page 2 - 4; Sum of Column 5 of Meter Counts table.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	14.94	14.81	0.14	0.9%	15.70	-0.76	-4.8%
Jun	12.17	11.74	0.42	3.6%	11.43	0.74	6.5%
Jul	9.94	9.97	-0.03	-0.3%	10.03	-0.09	-0.8%
Aug	9.85	10.19	-0.34	-3.3%	9.67	0.18	1.8%
Sep	10.53	10.69	-0.17	-1.6%	10.25	0.28	2.7%
Oct	13.02	13.20	-0.18	-1.3%	12.85	0.17	1.3%
Off-Peak	70.49	70.63	-0.15	-0.2%	69.95	0.52	0.7%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Residential Non-Heat Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	2,490	2,558	-68	-2.7%	-58	-11	2,562	-72	-2.8%	-40	-33
Jun	2,126	2,076	50	2.4%	-46	96	2,457	-332	-13.5%	-9	-323
Jul	1,352	1,902	-550	-28.9%	-93	-456	1,507	-155	-10.3%	-68	-87
Aug	1,786	1,682	104	6.2%	-82	185	1,801	-16	-0.9%	-82	66
Sep	1,634	1,931	-297	-15.4%	-85	-212	1,695	-61	-3.6%	-77	16
Oct	1,881	1,907	-25	-1.3%	-42	17	1,963	-82	-4.2%	-89	7
Off-Peak	11,269	12,056	-787	-6.5%	-419	-368	11,986	-718	-6.0%	-401	-317

Note 1 Company Forecast
Note 2 Actual, weather normalized data.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1,648	1,686	-38	-2.3%	1,674	-26	-1.6%
Jun	1,661	1,699	-38	-2.2%	1,667	-6	-0.4%
Jul	1,605	1,688	-83	-4.9%	1,681	-76	-4.5%
Aug	1,601	1,683	-82	-4.9%	1,677	-76	-4.5%
Sep	1,587	1,660	-73	-4.4%	1,663	-76	-4.6%
Oct	1,600	1,636	-36	-2.2%	1,676	-76	-4.5%
Off-Peak	1,617	1,675	-58	-3.5%	1,673	-56	-3.3%

Note 1 Company Forecast
Note 2 Actual Data.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1.51	1.52	-0.01	-0.4%	1.53	-0.02	-1.3%
Jun	1.28	1.22	0.06	4.7%	1.47	-0.19	-13.2%
Jul	0.84	1.13	-0.28	-25.2%	0.90	-0.05	-6.0%
Aug	1.12	1.00	0.12	11.6%	1.07	0.04	3.8%
Sep	1.03	1.16	-0.13	-11.5%	1.02	0.01	1.0%
Oct	1.18	1.17	0.01	0.9%	1.17	0.00	0.4%
Off-Peak	6.97	7.20	-0.23	-3.2%	7.16	-0.21	-3.0%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Residential Heat Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	94,928	94,707	222	0.2%	1,664	-1,443	106,345	-11,416	-10.7%	4,364	-15,780
Jun	59,856	57,139	2,718	4.8%	1,005	1,713	37,302	22,554	60.5%	1,661	20,893
Jul	44,063	39,079	4,983	12.8%	760	4,223	44,040	23	0.1%	1,584	-1,561
Aug	34,745	30,766	3,979	12.9%	624	3,355	32,461	2,284	7.0%	1,169	1,115
Sep	33,080	35,580	-2,500	-7.0%	694	-3,193	31,489	1,591	5.1%	1,132	459
Oct	44,397	49,618	-5,221	-10.5%	1,488	-6,709	41,685	2,712	6.5%	1,479	1,233
Off-Peak	311,069	306,888	4,181	1.4%	6,361	-2,180	293,321	17,748	6.1%	11,191	6,557

Note 1 Company Forecast
Note 2 Actual, weather normalized data.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	20,768	20,409	359	1.8%	19,949	819	4.1%
Jun	20,749	20,390	359	1.8%	19,864	885	4.5%
Jul	20,661	20,267	394	1.9%	19,944	717	3.6%
Aug	20,641	20,231	410	2.0%	19,924	717	3.6%
Sep	20,670	20,275	395	1.9%	19,953	717	3.6%
Oct	20,930	20,321	609	3.0%	20,213	717	3.5%
Off-Peak	20,737	20,316	421	2.1%	19,975	762	3.8%

Note 1 Company Forecast
Note 2 Actual Data.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	4.57	4.64	-0.07	-1.5%	5.33	-0.76	-14.3%
Jun	2.88	2.80	0.08	2.9%	1.88	1.01	53.6%
Jul	2.13	1.93	0.20	10.6%	2.21	-0.08	-3.4%
Aug	1.68	1.52	0.16	10.7%	1.63	0.05	3.3%
Sep	1.60	1.75	-0.15	-8.8%	1.58	0.02	1.4%
Oct	2.12	2.44	-0.32	-13.1%	2.06	0.06	2.9%
Off-Peak	15.00	15.11	-0.11	-0.7%	14.68	0.31	2.1%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Total Division C&I Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	331,816	322,703	9,114	2.8%	2,217	6,897	328,748	3,068	0.9%	3,106	-38
Jun	287,161	273,541	13,620	5.0%	1,754	11,867	277,477	9,684	3.5%	2,676	7,008
Jul	238,862	239,706	-844	-0.4%	5,228	-6,073	233,789	5,073	2.2%	3,528	1,546
Aug	244,636	253,598	-8,962	-3.5%	5,596	-14,558	234,718	9,919	4.2%	3,441	6,477
Sep	265,561	263,058	2,503	1.0%	4,052	-1,549	251,650	13,910	5.5%	3,793	10,117
Oct	330,218	320,313	9,905	3.1%	8,708	1,196	318,411	11,807	3.7%	4,707	7,100
Off-Peak	1,698,255	1,672,919	25,335	1.5%	27,765	-2,429	1,644,792	53,462	3.3%	21,572	31,890

Note 1 Company Forecast
Note 2 Actual, weather normalized data.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	6,306	6,263	43	0.7%	6,247	59	0.9%
Jun	6,283	6,243	40	0.6%	6,223	60	1.0%
Jul	6,327	6,192	135	2.2%	6,233	94	1.5%
Aug	6,301	6,165	136	2.2%	6,210	91	1.5%
Sep	6,266	6,171	95	1.5%	6,173	93	1.5%
Oct	6,387	6,218	169	2.7%	6,294	93	1.5%
Off-Peak	6,312	6,209	103	1.7%	6,230	82	1.3%

Note 1 Company Forecast
Note 2 Actual Data.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	52.62	51.53	1.09	2.1%	52.62	-0.01	0.0%
Jun	45.70	43.82	1.89	4.3%	44.59	1.12	2.5%
Jul	37.75	38.71	-0.96	-2.5%	37.51	0.24	0.7%
Aug	38.82	41.14	-2.31	-5.6%	37.80	1.03	2.7%
Sep	42.38	42.63	-0.25	-0.6%	40.77	1.61	4.0%
Oct	51.70	51.51	0.19	0.4%	50.59	1.11	2.2%
Off-Peak	269.06	269.45	-0.38	-0.1%	264.01	5.11	1.9%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Calendar Month Sales Service Usage (Dth)
(Total Forecast Deliveries times Sales Service Percentage)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-11	2,348	76,297	26,657	13,117	25,507	16,654	1,449	2,491	0	164,519
Jun-11	1,950	43,422	12,120	11,436	17,546	14,630	1,275	2,289	0	104,668
Jul-11	1,352	42,206	4,523	9,443	8,839	12,845	1,175	2,189	0	82,572
Aug-11	1,802	36,657	8,701	13,005	15,312	16,055	1,136	2,175	0	94,844
Sep-11	1,716	45,020	11,800	12,499	22,054	16,041	2,256	2,301	0	113,688
Oct-11	2,151	72,546	23,568	13,100	41,768	20,421	3,500	2,719	0	179,773
Total	11,319	316,150	87,368	72,599	131,026	96,646	10,791	14,164	0	740,064

Forecast Calendar Month Distribution Service Usage (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-11	2,348	76,297	33,415	15,596	43,149	26,645	15,975	88,645	81,151	383,221
Jun-11	1,950	43,422	15,192	13,597	29,683	23,406	14,061	81,464	85,379	308,155
Jul-11	1,352	42,206	5,670	11,228	14,953	20,550	12,963	77,893	92,725	279,541
Aug-11	1,802	36,657	10,907	15,463	25,904	25,687	12,526	77,402	79,567	285,914
Sep-11	1,716	45,020	14,791	14,862	37,309	25,665	24,884	81,873	83,308	329,429
Oct-11	2,151	72,546	29,543	15,576	70,659	32,671	38,595	96,774	88,790	447,305
Total	11,319	316,150	109,518	86,321	221,657	154,624	119,005	504,051	510,920	2,033,565

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	42.9%
Jun-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	34.0%
Jul-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	29.5%
Aug-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	33.2%
Sep-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	34.5%
Oct-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	40.2%

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Billed Sales Service Usage (Dth)
(Forecast Billed Distribution Usage times Sales Service Percentage)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-11	2,490	94,928	32,612	13,797	35,544	17,895	1,449	2,491	0	201,206
Jun-11	2,126	59,856	17,365	12,329	26,096	16,054	1,275	2,289	0	137,389
Jul-11	1,352	44,063	5,274	9,406	10,026	12,828	1,175	2,189	0	86,314
Aug-11	1,786	34,745	8,082	12,918	14,302	15,911	1,136	2,175	0	91,055
Sep-11	1,634	33,080	7,909	12,148	15,703	15,359	2,256	2,301	0	90,390
Oct-11	1,881	44,397	14,423	11,701	26,684	18,080	3,500	2,719	0	123,386
Total	11,269	311,069	85,665	72,299	128,354	96,128	10,791	14,164	0	729,739

Forecast Billed Distribution Service Usage (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-11	2,490	94,928	40,880	16,405	60,129	28,631	15,975	88,645	81,151	429,234
Jun-11	2,126	59,856	21,767	14,659	44,146	25,685	14,061	81,464	85,379	349,143
Jul-11	1,352	44,063	6,611	11,184	16,961	20,524	12,963	77,893	92,725	284,277
Aug-11	1,786	34,745	10,131	15,360	24,194	25,456	12,526	77,402	79,567	281,167
Sep-11	1,634	33,080	9,914	14,444	26,564	24,573	24,884	81,873	83,308	300,274
Oct-11	1,881	44,397	18,080	13,912	45,141	28,926	38,595	96,774	88,790	376,496
Total	11,269	311,069	107,383	85,965	217,136	153,795	119,005	504,051	510,920	2,020,593

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	46.9%
Jun-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	39.4%
Jul-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	30.4%
Aug-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	32.4%
Sep-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	30.1%
Oct-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	32.8%

Northern Utilities, Inc.
New Hampshire Division
Estimation of Northern City-Gate Receipts Required to Meet Sales Service Deliveries Forecast

Month	Calendar Month Distribution Service Usage (Dth)	Estimated Company Use Factor	Estimated Company Use (Dth)	Billed Sales Service Deliveries (Dth)	Unbilled Sales Service Deliveries (Dth)	Calendar Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Lost and Unaccounted For (Percent)	Lost and Unaccounted For (Dth)	Estimated Division City-Gate Receipts (Dth)
May-11	383,221	0.02%	59	201,206	-36,687	164,519	164,577	0.98%	1,629	166,206
Jun-11	308,155	0.07%	208	137,389	-32,722	104,668	104,876	0.98%	1,038	105,914
Jul-11	279,541	0.04%	112	86,314	-3,742	82,572	82,684	0.98%	819	83,503
Aug-11	285,914	0.08%	227	91,055	3,789	94,844	95,071	0.98%	941	96,012
Sep-11	329,429	0.09%	296	90,390	23,299	113,688	113,985	0.98%	1,128	115,113
Oct-11	447,305	0.06%	264	123,386	56,388	179,773	180,038	0.98%	1,782	181,820
Off-Peak	2,033,565	0.06%	1,167	729,739	10,325	740,064	741,231	0.98%	7,337	748,568

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
1	**BASE SENDOUT BY CLASS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
2	**Total Therms**							
3	Res Heat	398,955	386,086	398,955	371,089	386,086	398,955	2,340,127
4	Res General	15,958	15,443	13,670	15,958	15,443	15,958	92,431
5	G50 Low Annual-Low Winter	113,572	109,908	95,493	113,572	109,908	113,572	656,026
6	G40 Low Annual-High Winter	66,910	64,751	45,740	66,910	64,751	66,910	375,972
7	G51 Med Annual-Low Winter	146,213	141,497	129,896	146,213	141,497	146,213	851,530
8	G41 Med Annual-High Winter	122,197	118,256	89,387	122,197	118,256	122,197	692,490
9	G52 High Annual-Low Winter	22,076	21,364	22,076	22,018	21,364	22,076	130,975
10	G42 High Annual-High Winter	11,693	11,315	11,693	11,498	11,315	11,693	69,207
11	Total Firm Sales	897,575	868,621	806,910	869,455	868,621	897,575	5,208,758
12	**% of Total**							
13	Res Heat	44.45%	44.45%	49.44%	42.68%	44.45%	44.45%	
14	Res General	1.78%	1.78%	1.69%	1.84%	1.78%	1.78%	
15	G50 Low Annual-Low Winter	12.65%	12.65%	11.83%	13.06%	12.65%	12.65%	
16	G40 Low Annual-High Winter	7.45%	7.45%	5.67%	7.70%	7.45%	7.45%	
17	G51 Med Annual-Low Winter	16.29%	16.29%	16.10%	16.82%	16.29%	16.29%	
18	G41 Med Annual-High Winter	13.61%	13.61%	11.08%	14.05%	13.61%	13.61%	
19	G52 High Annual-Low Winter	2.46%	2.46%	2.74%	2.53%	2.46%	2.46%	
20	G42 High Annual-High Winter	1.30%	1.30%	1.45%	1.32%	1.30%	1.30%	
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

22	**BASE COMMODITY COSTS Excld Hedging**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
23	TOTAL BASE COMMODITY Excld Hedging	$ 389,308	$ 379,271	$ 357,448	$ 388,533	$ 389,617	$ 409,188	$ 2,313,365
24	Res Heat	$ 173,040	$ 168,579	$ 176,731	$ 165,828	$ 173,178	$ 181,876	$ 1,039,232
25	Res General	$ 6,922	$ 6,743	$ 6,056	$ 7,131	$ 6,927	$ 7,275	$ 41,053
26	G50 Low Annual-Low Winter	$ 49,260	$ 47,990	$ 42,302	$ 50,752	$ 49,299	$ 51,775	$ 291,378
27	G40 Low Annual-High Winter	$ 29,021	$ 28,273	$ 20,262	$ 29,900	$ 29,044	$ 30,503	$ 167,003
28	G51 Med Annual-Low Winter	$ 63,418	$ 61,783	$ 57,542	$ 65,338	$ 63,468	$ 66,656	$ 378,204
29	G41 Med Annual-High Winter	$ 53,001	$ 51,635	$ 39,597	$ 54,606	$ 53,043	$ 55,708	$ 307,589
30	G52 High Annual-Low Winter	$ 9,575	$ 9,328	$ 9,779	$ 9,839	$ 9,583	$ 10,064	$ 58,169
31	G42 High Annual-High Winter	$ 5,071	$ 4,941	$ 5,180	$ 5,138	$ 5,076	$ 5,330	$ 30,736
32								
33	Residential	$ 179,962	$ 175,322	$ 182,786	$ 172,960	$ 180,105	$ 189,151	$ 1,080,285
34	SALES HLF CLASSES	$ 122,253	$ 119,101	$ 109,623	$ 125,929	$ 122,350	$ 128,496	$ 727,752
35	SALES LLF CLASSES	$ 87,093	$ 84,848	$ 65,038	$ 89,644	$ 87,163	$ 91,541	$ 505,328

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
37	TOTAL BASE HEDGING COMMODITY	$ 31,473	$ -	$ -	$ -	$ -	$ 17,733	$ 49,206
38	Res Heat	$ 13,989	$ -	$ -	$ -	$ -	$ 7,882	$ 21,871
39	Res General	$ 560	$ -	$ -	$ -	$ -	$ 315	$ 875
40	G50 Low Annual-Low Winter	$ 3,982	$ -	$ -	$ -	$ -	$ 2,244	$ 6,226
41	G40 Low Annual-High Winter	$ 2,346	$ -	$ -	$ -	$ -	$ 1,322	$ 3,668
42	G51 Med Annual-Low Winter	$ 5,127	$ -	$ -	$ -	$ -	$ 2,889	$ 8,016
43	G41 Med Annual-High Winter	$ 4,285	$ -	$ -	$ -	$ -	$ 2,414	$ 6,699
44	G52 High Annual-Low Winter	$ 774	$ -	$ -	$ -	$ -	$ 436	$ 1,210
45	G42 High Annual-High Winter	$ 410	$ -	$ -	$ -	$ -	$ 231	$ 641
46								
47	Residential	$ 14,549	$ -	$ -	$ -	$ -	$ 8,197	$ 22,746
48	SALES HLF CLASSES	$ 9,883	$ -	$ -	$ -	$ -	$ 5,569	$ 15,452
49	SALES LLF CLASSES	$ 7,041	$ -	$ -	$ -	$ -	$ 3,967	$ 11,008

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	
2	**Total Therms**	
3	Res Heat	Schedule 10B, LN 52
4	Res General	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	Schedule 10B, LN 58
10	G42 High Annual-High Winter	Schedule 10B, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12	**% of Total**	
13	Res Heat	LN 3 / LN 11
14	Res General	LN 4 / LN 11
15	G50 Low Annual-Low Winter	LN 5 / LN 11
16	G40 Low Annual-High Winter	LN 6 / LN 11
17	G51 Med Annual-Low Winter	LN 7 / LN 11
18	G41 Med Annual-High Winter	LN 8 / LN 11
19	G52 High Annual-Low Winter	LN 9 / LN 11
20	G42 High Annual-High Winter	LN 10 / LN 11
21	Total Firm Sales	LN 11 / LN 11

22	**BASE COMMODITY COSTS Excld Hedging**	
23	TOTAL BASE COMMODITY Excld Hedging	Schedule 1B, LN 37
24	Res Heat	LN 23 * LN 13
25	Res General	LN 23 * LN 14
26	G50 Low Annual-Low Winter	LN 23 * LN 15
27	G40 Low Annual-High Winter	LN 23 * LN 16
28	G51 Med Annual-Low Winter	LN 23 * LN 17
29	G41 Med Annual-High Winter	LN 23 * LN 18
30	G52 High Annual-Low Winter	LN 23 * LN 19
31	G42 High Annual-High Winter	LN 23 * LN 20
32		
33	Residential	LN 24 + LN 25
34	SALES HLF CLASSES	LN 26 + LN 28 + LN 30
35	SALES LLF CLASSES	LN 27 + LN 29 + LN 31

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	
37	TOTAL BASE HEDGING COMMODITY	Schedule 1B, LN 38
38	Res Heat	LN 13 * LN 37
39	Res General	LN 14 * LN 37
40	G50 Low Annual-Low Winter	LN 15 * LN 37
41	G40 Low Annual-High Winter	LN 16 * LN 37
42	G51 Med Annual-Low Winter	LN 17 * LN 37
43	G41 Med Annual-High Winter	LN 18 * LN 37
44	G52 High Annual-Low Winter	LN 19 * LN 37
45	G42 High Annual-High Winter	LN 20 * LN 37
46		
47	Residential	LN 38 + LN 39
48	SALES HLF CLASSES	LN 40 + LN 42 + LN 44
49	SALES LLF CLASSES	LN 41 + LN 43 + LN 45

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
51	**Total Therms**							
52	Res Heat	371,839	53,306	27,867	-	69,759	334,768	857,538
53	Res General	7,764	4,289	-	2,288	1,932	5,796	22,070
54	G50 Low Annual-Low Winter	18,942	5,810	-	18,079	16,651	18,917	78,398
55	G40 Low Annual-High Winter	202,390	57,889	-	21,170	54,725	171,456	507,630
56	G51 Med Annual-Low Winter	22,035	6,544	-	16,317	20,927	60,320	126,143
57	G41 Med Annual-High Winter	135,485	59,294	-	32,811	105,052	300,238	632,880
58	G52 High Annual-Low Winter	3,089	1,800	58	-	1,931	5,427	12,304
59	G42 High Annual-High Winter	2,942	1,587	195	-	11,532	23,703	39,958
60	Total Firm Sales	764,485	190,519	28,120	90,665	282,509	920,625	2,276,922
61	**% of Total**							
62	Res Heat	48.64%	27.98%	23.46%	23.46%	24.69%	36.36%	
63	Res General	1.02%	2.25%	1.93%	1.93%	0.68%	0.63%	
64	G50 Low Annual-Low Winter	2.48%	3.05%	15.22%	15.22%	5.89%	2.05%	
65	G40 Low Annual-High Winter	26.47%	30.38%	17.82%	17.82%	19.37%	18.62%	
66	G51 Med Annual-Low Winter	2.88%	3.43%	13.74%	13.74%	7.41%	6.55%	
67	G41 Med Annual-High Winter	17.72%	31.12%	27.62%	27.62%	37.19%	32.61%	
68	G52 High Annual-Low Winter	0.40%	0.94%	0.05%	0.05%	0.68%	0.59%	
69	G42 High Annual-High Winter	0.38%	0.83%	0.16%	0.16%	4.08%	2.57%	
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
72	REMAINING COMMODITY Excld Hedging	$ 332,164	$ 83,898	$ 13,348	$ 41,429	$ 127,679	$ 420,717	$ 1,019,236
73	Res Heat	$ 161,562	$ 23,474	$ 3,131	$ 9,719	$ 31,527	$ 152,986	$ 382,400
74	Res General	$ 3,374	$ 1,889	$ 257	$ 798	$ 873	$ 2,649	$ 9,840
75	G50 Low Annual-Low Winter	$ 8,230	$ 2,559	$ 2,032	$ 6,305	$ 7,526	$ 8,645	$ 35,296
76	G40 Low Annual-High Winter	$ 87,937	$ 25,492	$ 2,379	$ 7,384	$ 24,733	$ 78,354	$ 226,279
77	G51 Med Annual-Low Winter	$ 9,574	$ 2,882	$ 1,834	$ 5,691	$ 9,458	$ 27,566	$ 57,004
78	G41 Med Annual-High Winter	$ 58,867	$ 26,111	$ 3,687	$ 11,444	$ 47,478	$ 137,206	$ 284,793
79	G52 High Annual-Low Winter	$ 1,342	$ 793	$ 7	$ 20	$ 873	$ 2,480	$ 5,514
80	G42 High Annual-High Winter	$ 1,278	$ 699	$ 22	$ 68	$ 5,212	$ 10,832	$ 18,110
81								
82	Residential	$ 164,935	$ 25,363	$ 3,389	$ 10,517	$ 32,401	$ 155,635	$ 392,239
83	SALES HLF CLASSES	$ 19,146	$ 6,233	$ 3,872	$ 12,017	$ 17,856	$ 38,690	$ 97,814
84	SALES LLF CLASSES	$ 148,083	$ 52,302	$ 6,088	$ 18,895	$ 77,423	$ 226,392	$ 529,183

85	**REMAINING COMMODITY HEDGING COSTS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
86	TOTAL REMAINING COMMODITY HEDGING	$ 26,540	$ -	$ -	$ -	$ -	$ 18,046	$ 44,586
87	Res Heat	$ 12,909	$ -	$ -	$ -	$ -	$ 6,562	$ 19,471
88	Res General	$ 270	$ -	$ -	$ -	$ -	$ 114	$ 383
89	G50 Low Annual-Low Winter	$ 658	$ -	$ -	$ -	$ -	$ 371	$ 1,028
90	G40 Low Annual-High Winter	$ 7,026	$ -	$ -	$ -	$ -	$ 3,361	$ 10,387
91	G51 Med Annual-Low Winter	$ 765	$ -	$ -	$ -	$ -	$ 1,182	$ 1,947
92	G41 Med Annual-High Winter	$ 4,703	$ -	$ -	$ -	$ -	$ 5,885	$ 10,589
93	G52 High Annual-Low Winter	$ 107	$ -	$ -	$ -	$ -	$ 106	$ 214
94	G42 High Annual-High Winter	$ 102	$ -	$ -	$ -	$ -	$ 465	$ 567
95								$ -
96	Residential	$ 13,178	$ -	$ -	$ -	$ -	$ 6,676	$ 19,854
97	SALES HLF CLASSES	$ 1,530	$ -	$ -	$ -	$ -	$ 1,660	$ 3,189
98	SALES LLF CLASSES	$ 11,832	$ -	$ -	$ -	$ -	$ 9,711	$ 21,543

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	
51	**Total Therms**	
52	Res Heat	Schedule 10B, LN 68
53	Res General	Schedule 10B, LN 69
54	G50 Low Annual-Low Winter	Schedule 10B, LN 70
55	G40 Low Annual-High Winter	Schedule 10B, LN 71
56	G51 Med Annual-Low Winter	Schedule 10B, LN 72
57	G41 Med Annual-High Winter	Schedule 10B, LN 73
58	G52 High Annual-Low Winter	Schedule 10B, LN 74
59	G42 High Annual-High Winter	Schedule 10B, LN 75
60	Total Firm Sales	Sum LN 52 : LN 59
61	**% of Total**	
62	Res Heat	LN 52 / LN 60, Jul/Aug calculated together
63	Res General	LN 53 / LN 60, Jul/Aug calculated together
64	G50 Low Annual-Low Winter	LN 54 / LN 60, Jul/Aug calculated together
65	G40 Low Annual-High Winter	LN 55 / LN 60, Jul/Aug calculated together
66	G51 Med Annual-Low Winter	LN 56 / LN 60, Jul/Aug calculated together
67	G41 Med Annual-High Winter	LN 57 / LN 60, Jul/Aug calculated together
68	G52 High Annual-Low Winter	LN 58 / LN 60, Jul/Aug calculated together
69	G42 High Annual-High Winter	LN 59 / LN 60, Jul/Aug calculated together
70	Total Firm Sales	LN 60 / LN 60, Jul/Aug calculated together
71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	
72	REMAINING COMMODITY Excld Hedging	Schedule 1B, LN 39
73	Res Heat	LN 72 * LN 62
74	Res General	LN 72 * LN 63
75	G50 Low Annual-Low Winter	LN 72 * LN 64
76	G40 Low Annual-High Winter	LN 72 * LN 65
77	G51 Med Annual-Low Winter	LN 72 * LN 66
78	G41 Med Annual-High Winter	LN 72 * LN 67
79	G52 High Annual-Low Winter	LN 72 * LN 68
80	G42 High Annual-High Winter	LN 72 * LN 69
81		
82	Residential	LN 73 + LN 74
83	SALES HLF CLASSES	LN 75 + LN 77 + LN 79
84	SALES LLF CLASSES	LN 76 + LN 78 + LN 80
85	**REMAINING COMMODITY HEDGING COSTS**	
86	TOTAL REMAINING COMMODITY HEDGING	Schedule 1B, LN 40
87	Res Heat	LN 62 * LN 86
88	Res General	LN 63 * LN 86
89	G50 Low Annual-Low Winter	LN 64 * LN 86
90	G40 Low Annual-High Winter	LN 65 * LN 86
91	G51 Med Annual-Low Winter	LN 66 * LN 86
92	G41 Med Annual-High Winter	LN 67 * LN 86
93	G52 High Annual-Low Winter	LN 68 * LN 86
94	G42 High Annual-High Winter	LN 69 * LN 86
95		
96	Residential	LN 87 + LN 88
97	SALES HLF CLASSES	LN 89 + LN 91 + LN 93
98	SALES LLF CLASSES	LN 90 + LN 92 + LN 94

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
100	TOTAL COMMODITY Excld Hedging	$ 721,472	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 829,905	$ 3,332,601
101	Res Heat	$ 334,602	$ 192,053	$ 179,862	$ 175,548	$ 204,705	$ 334,862	$ 1,421,632
102	Res General	$ 10,295	$ 8,632	$ 6,313	$ 7,929	$ 7,800	$ 9,924	$ 50,893
103	G50 Low Annual-Low Winter	$ 57,490	$ 50,549	$ 44,334	$ 57,057	$ 56,825	$ 60,420	$ 326,674
104	G40 Low Annual-High Winter	$ 116,958	$ 53,765	$ 22,641	$ 37,284	$ 53,777	$ 108,857	$ 393,282
105	G51 Med Annual-Low Winter	$ 72,991	$ 64,664	$ 59,375	$ 71,029	$ 72,926	$ 94,222	$ 435,208
106	G41 Med Annual-High Winter	$ 111,868	$ 77,746	$ 43,284	$ 66,050	$ 100,521	$ 192,914	$ 592,383
107	G52 High Annual-Low Winter	$ 10,917	$ 10,121	$ 9,786	$ 9,859	$ 10,455	$ 12,544	$ 63,683
108	G42 High Annual-High Winter	$ 6,350	$ 5,640	$ 5,202	$ 5,206	$ 10,287	$ 16,162	$ 48,846
109								
110	Residential	$ 344,897	$ 200,685	$ 186,175	$ 183,477	$ 212,505	$ 344,786	$ 1,472,525
111	SALES HLF CLASSES	$ 141,399	$ 125,334	$ 113,495	$ 137,946	$ 140,206	$ 167,186	$ 825,565
112	SALES LLF CLASSES	$ 235,176	$ 137,150	$ 71,126	$ 108,540	$ 164,585	$ 317,933	$ 1,034,511

113	**TOTAL HEDGING COMMODITY COSTS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
114	TOTAL HEDGING COMMODITY	$ 58,012	$ -	$ -	$ -	$ -	$ 35,780	$ 93,792
115	Res Heat	$ 26,898	$ -	$ -	$ -	$ -	$ 14,444	$ 41,342
116	Res General	$ 829	$ -	$ -	$ -	$ -	$ 429	$ 1,258
117	G50 Low Annual-Low Winter	$ 4,640	$ -	$ -	$ -	$ -	$ 2,615	$ 7,255
118	G40 Low Annual-High Winter	$ 9,372	$ -	$ -	$ -	$ -	$ 4,683	$ 14,055
119	G51 Med Annual-Low Winter	$ 5,892	$ -	$ -	$ -	$ -	$ 4,071	$ 9,963
120	G41 Med Annual-High Winter	$ 8,988	$ -	$ -	$ -	$ -	$ 8,300	$ 17,288
121	G52 High Annual-Low Winter	$ 881	$ -	$ -	$ -	$ -	$ 543	$ 1,424
122	G42 High Annual-High Winter	$ 512	$ -	$ -	$ -	$ -	$ 696	$ 1,208
123								
124	Residential	$ 27,727	$ -	$ -	$ -	$ -	$ 14,873	$ 42,600
125	SALES HLF CLASSES	$ 11,413	$ -	$ -	$ -	$ -	$ 7,228	$ 18,641
126	SALES LLF CLASSES	$ 18,873	$ -	$ -	$ -	$ -	$ 13,678	$ 32,551

127	TOTAL COMMODITY	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
128	Res Heat	$ 361,499	$ 192,053	$ 179,862	$ 175,548	$ 204,705	$ 349,307	$ 1,462,974
129	Res General	$ 11,124	$ 8,632	$ 6,313	$ 7,929	$ 7,800	$ 10,353	$ 52,151
130	G50 Low Annual-Low Winter	$ 62,130	$ 50,549	$ 44,334	$ 57,057	$ 56,825	$ 63,035	$ 333,929
131	G40 Low Annual-High Winter	$ 126,330	$ 53,765	$ 22,641	$ 37,284	$ 53,777	$ 113,540	$ 407,337
132	G51 Med Annual-Low Winter	$ 78,883	$ 64,664	$ 59,375	$ 71,029	$ 72,926	$ 98,293	$ 445,171
133	G41 Med Annual-High Winter	$ 120,857	$ 77,746	$ 43,284	$ 66,050	$ 100,521	$ 201,213	$ 609,671
134	G52 High Annual-Low Winter	$ 11,798	$ 10,121	$ 9,786	$ 9,859	$ 10,455	$ 13,087	$ 65,107
135	G42 High Annual-High Winter	$ 6,862	$ 5,640	$ 5,202	$ 5,206	$ 10,287	$ 16,858	$ 50,054
136	Total Firm Sales	$ 779,484	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 865,685	$ 3,426,393
137								
138	Residential	$ 372,624	$ 200,685	$ 186,175	$ 183,477	$ 212,505	$ 359,659	$ 1,515,125
139	SALES HLF CLASSES	$ 152,811	$ 125,334	$ 113,495	$ 137,946	$ 140,206	$ 174,414	$ 844,207
140	SALES LLF CLASSES	$ 254,049	$ 137,150	$ 71,126	$ 108,540	$ 164,585	$ 331,611	$ 1,067,061
141								
142	% ALLOCATION BETWEEN SALES HLF AND LLF							
143	SALES HLF CLASSES							44.17%
144	SALES LLF CLASSES							55.83%

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	
100	TOTAL COMMODITY Excld Hedging	Schedule 1B, LN 41
101	Res Heat	LN 24 + LN 73
102	Res General	LN 25 + LN 74
103	G50 Low Annual-Low Winter	LN 26 + LN 75
104	G40 Low Annual-High Winter	LN 27 + LN 76
105	G51 Med Annual-Low Winter	LN 28 + LN 77
106	G41 Med Annual-High Winter	LN 29 + LN 78
107	G52 High Annual-Low Winter	LN 30 + LN 79
108	G42 High Annual-High Winter	LN 31 + LN 80
109		
110	Residential	LN 101 + LN 102
111	SALES HLF CLASSES	LN 103 + LN 105 + LN 107
112	SALES LLF CLASSES	LN 104 + LN 106 + LN 108

113	**TOTAL HEDGING COMMODITY COSTS**	
114	TOTAL HEDGING COMMODITY	Schedule 1B, LN 42
115	Res Heat	LN 38 + LN 87
116	Res General	LN 39 + LN 88
117	G50 Low Annual-Low Winter	LN 40 + LN 89
118	G40 Low Annual-High Winter	LN 41 + LN 90
119	G51 Med Annual-Low Winter	LN 42 + LN 91
120	G41 Med Annual-High Winter	LN 43 + LN 92
121	G52 High Annual-Low Winter	LN 44 + LN 93
122	G42 High Annual-High Winter	LN 45 + LN 94
123		
124	Residential	LN 115 + LN 116
125	SALES HLF CLASSES	LN 117 + LN 119 + LN 121
126	SALES LLF CLASSES	LN 118 + LN 120 + LN 122

127	**TOTAL COMMODITY**	
128	Res Heat	LN 101 + LN 115
129	Res General	LN 102 + LN 116
130	G50 Low Annual-Low Winter	LN 103 + LN 117
131	G40 Low Annual-High Winter	LN 104 + LN 118
132	G51 Med Annual-Low Winter	LN 105 + LN 119
133	G41 Med Annual-High Winter	LN 106 + LN 120
134	G52 High Annual-Low Winter	LN 107 + LN 121
135	G42 High Annual-High Winter	LN 108 + LN 122
136	Total Firm Sales	Sum LN 128 : LN 135
137		
138	Residential	LN 128 + LN 129
139	SALES HLF CLASSES	LN 130 + LN 132 + LN 134
140	SALES LLF CLASSES	LN 131 + LN 133 + LN 135
141		
142	% ALLOCATION BETWEEN SALES HLF AND LLF	
143	SALES HLF CLASSES	LN 139 / (LN 139 + LN 140)
144	SALES LLF CLASSES	LN 140 / (LN 139 + LN 140)

Schedule 11

Northern Utilities, Inc.

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) May 2011 through October 2011							
Description	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Season
Pipeline							
Chicago	177,969	163,742	139,235	129,731	153,671	179,215	943,562
PNGTS	31,826	16,603	0	31,826	30,800	31,826	142,882
Niagara	3,133	8,493	0	8,872	27,661	83,287	131,446
Tennessee Production	91,315	0	0	5,860	4,135	55,521	156,831
Pipeline Subtotal	**304,244**	**188,838**	**139,235**	**176,289**	**216,266**	**349,849**	**1,374,721**
Storage							
Tennessee Storage	0	0	0	0	0	0	0
Washington 10 Storage	0	0	0	0	0	0	0
Storage Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Peaking							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
LNG	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Peaking Subtotal	**1,395**	**1,350**	**1,395**	**1,395**	**1,350**	**1,395**	**8,280**
Total Delivered (Dth)	**305,639**	**190,188**	**140,630**	**177,684**	**217,616**	**351,244**	**1,383,001**

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 12

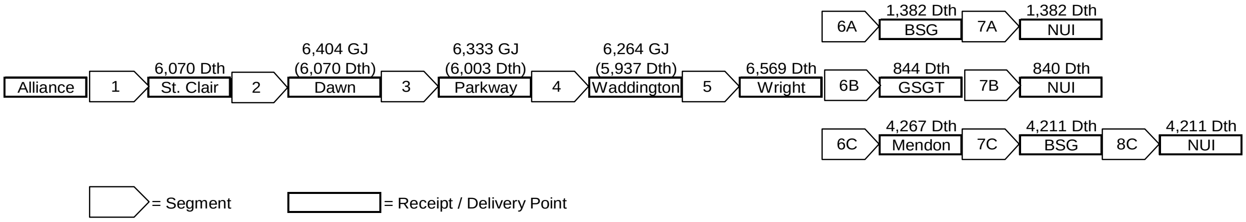
Northern Utilities, Inc.

Northern Capacity by Source of Supply (Dth per Day)		
Supply Source:	Northern Deliverable Winter Capacity (Nov - Mar)	Northern Deliverable Summer Capacity (Apr-Oct)
Chicago (Interconnection of Alliance and Vector Pipelines)	6,433	6,433
Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)	1,095	1,095
Niagara (Interconnection of TransCanada and Tennessee Pipelines)	3,280	3,280
Tennessee Production Area	13,089	13,089
Washington 10 Storage	32,835	0
Tennessee Firm Storage - Market Area	2,640	2,640
Peaking Supply 1	4,975	4,975
Peaking Supply 2	57,113	0
Lewiston LNG Facility	10,000	10,000
Total Deliverable Capacity	131,460	41,512

Released Capacity	
Supply Source:	Northern Deliverable Capacity (Dth per Day)
Texas Eastern Production and Storage & Algonquin (Centerville, NJ)	286
Texas Eastern Zone M3	965
Total Released Capacity	1,251

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Chicago (Interconnection of Alliance and Vector Pipelines)

Capacity Path Diagram

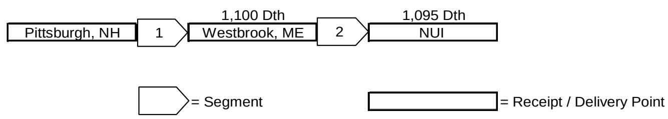


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	Union
3	Transportation	Union	M12205	M12	10/31/2017	6,333	GJ	Year-Round	Dawn	Parkway	TransCanada
4	Transportation	TransCanada	41235	FT	10/31/2017	6,264	GJ	Year-Round	Parkway	Waddington	Iroquois
5	Transportation	Iroquois	R181001	RTS-1	10/31/2013	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
6A	Transportation	Tennessee	31861	NET-284	10/31/2012	1,382	Dth	Year-Round	Wright	Bay State City Gate	
7A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
6B	Transportation	Tennessee	31861	NET-284	10/31/2012	844	Dth	Year-Round	Wright	Pleasant St.	Granite
7B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	840	Dth	Year-Round	Granite	Northern City Gates	
6C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
7C	Transportation	Algonquin	93200F	AFT-1	10/31/2012	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
8C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,433	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)

Capacity Path Diagram

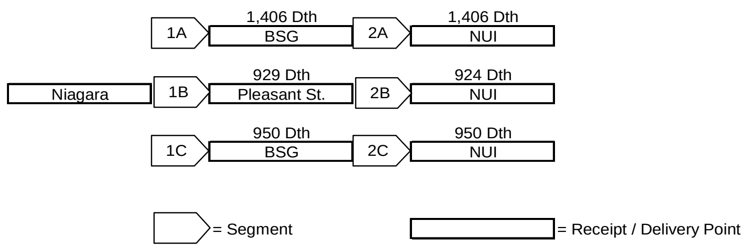


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	1,095	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						1,095	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Niagara (Interconnection of TransCanada and Tennessee Pipelines)

Capacity Path Diagram

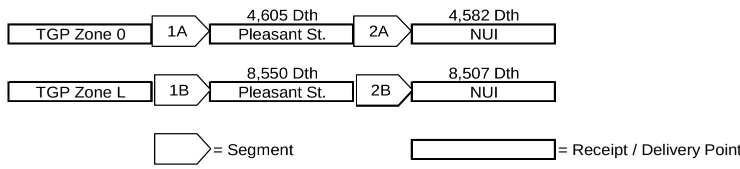


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2015	1,406	Dth	Year-Round	Niagara	Bay State City Gate	
2A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,406	Dth	Year-Round	Bay State City Gate	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2015	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	924	Dth	Year-Round	Granite	Northern City Gates	
1C	Transportation	Tennessee	46314	FT-A	3/31/2012	950	Dth	Year-Round	Niagara	Bay State City Gate	
2C	Exchange	Bay State Gas	NA	NA	Renewal Clause	950	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						3,280	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Production Area

Capacity Path Diagram



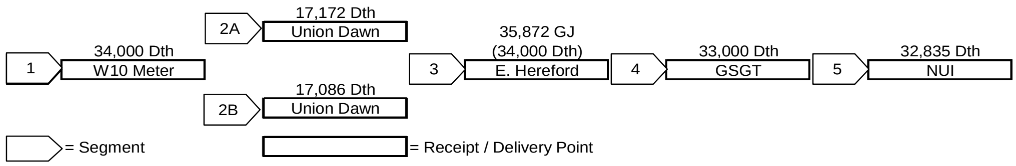
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	4,582	Dth	Year-Round	Granite	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	8,507	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,089	Dth				

Note 1: Tennessee Contract No. 5083 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Washington 10 Storage

Capacity Path Diagram



Capacity Path Detail

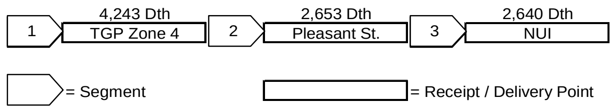
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-0725	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-0727	FT	3/31/2017	17,086	Dth	Winter Only (Nov - Mar)	W10 Withdrawal Meter	Union Dawn	TransCanada
3	Transportation	TransCanada	33322	FT	3/31/2018	35,872	GJ	Year-Round	Union Dawn	East Hereford	PNGTS
4	Transportation	PNGTS	1997-004	FT	3/9/2019	33,000	Dth	Winter Only (Nov - Mar)	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	32,835	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,835	Dth				

Note 1: Washington 10 Contract 01052 has a maximum storage quantity of 3,400,000 Dth.

Note 2: Vector Contract No. CRL-NUI-0725 allows for receipt from the Alliance Interconnect (Chicago). Gas is received on this contract at the W10 Withdrawal meter on a secondary, firm basis. This capacity is used for summer refill of the Washington 10 storage contract.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Firm Storage - Market Area

Capacity Path Diagram



Capacity Path Detail

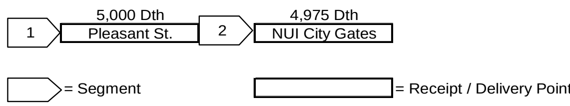
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	10/31/2013	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	10/31/2013	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	2,640	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,640	Dth				

Note 1: Tennessee Contract No. 5195 has a maximum storage quantity of 259,337 Dth.

Note 2: Tennessee Contract No. 5265 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Supply 1

Capacity Path Diagram



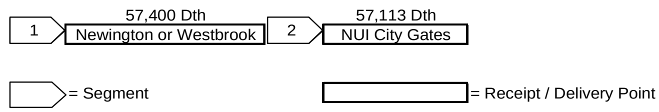
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Distrigas	NA	NA	10/31/2011	5,000	Dth	Year-Round	NA	Pleasant St.	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	4,975	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						4,975	Dth				

Note 1: Peaking Supply 1 Contract allows Northern to nominate an additional 5,000 Dth per Day of liquified LNG, which Northern delivers to its Lewiston LNG facility via truck. Annual maximum take is 755,000 Dth.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Supply 2

Capacity Path Diagram



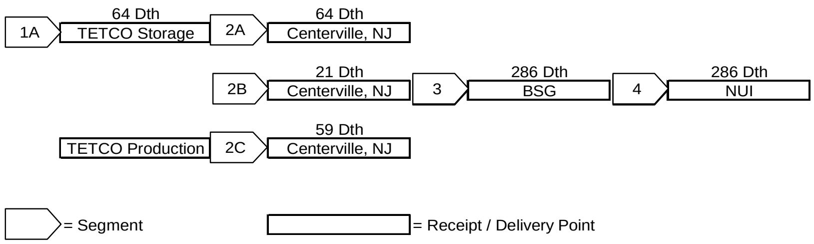
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	FPL Energy	NA	NA	3/31/2011	57,400	Dth	Winter Only (Nov-Mar)	NA	Newington, NH or Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	57,113	Dth	Year-Round	Newington, NH or Westbrook, ME	Northern City Gates	
Total Path Deliverable						57,113	Dth				

Note 1. Effective November 1, 2010, the Peaking Supply 2 Contract MDQ increases from 53,000 Dth to 57,400 Dth. The annual maximum take is 1,272,000 Dth, which increases to 1,435,000 Dth effective November 1, 2010.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Texas Eastern Production and Storage & Algonquin (Centerville, NJ)

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Storage	Texas Eastern	400513	FSS-1	4/30/2012	64	Dth	Year-Round		Texas Eastern M3 Storage	
2A	Transportation	Texas Eastern	800436	CDS	10/31/2012	64	Dth	Year-Round	Texas Eastern M3 Storage	Centerville, NJ	Algonquin
2B[2]	Storage	Texas Eastern	400215	SS-1	4/30/2013	21	Dth	Year-Round	Texas Eastern M3 Storage	Centerville, NJ	Algonquin
2C	Transportation	Texas Eastern	800464	CDS	10/31/2012	59	Dth	Year-Round	Texas Eastern Production Area	Centerville, NJ	Algonquin
3[3]	Transportation	Algonquin	93201A1C	AFT-1	10/31/2012	286	Dth	Year-Round	Centerville, NJ	Bay State City Gate	
4	Exchange	Bay State Gas	NA	NA	Renewal Clause	286	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						286	Dth				

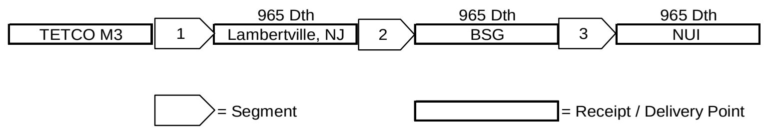
Note 1: Texas Eastern Contract No. 400513 has a maximum storage quantity of 3,840 Dth.

Note 2: Texas Eastern Contract No. 400215 has a maximum storage quantity of 1,470 Dth.

Note 3: Northern has entered into a permanent release of Algonquin Contract No. 93201A1C. As such, these supplies are not deliverable to Northern City Gates. Northern plans to continue to seek permanent release of the other Texas Eastern contracts in this capacity path.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Texas Eastern Zone M3

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Transportation	Texas Eastern	800384	FT-1	10/31/2017	965	Dth	Year-Round	Texas Eastern M3 Storage	Lambertville, NJ	Algonquin
2[1]	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2012	965	Dth	Year-Round	Lambertville, NJ	Bay State City Gate	
3	Exchange	Bay State Gas	NA	NA	Renewal Clause	965	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						965	Dth				

Note 1: Northern has entered into a permanent release of both Texas Eastern Contract No. 800384 and Algonquin Contract No. 93201A1C. As such, these supplies are not deliverable to Northern City Gates.

Schedule 13

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2010 through October 2011

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	712,812	37%	87%
G50	166,544	9%	78%
G41	695,040	36%	60%
G51	236,869	12%	61%
G42	80,481	4%	18%
G52	20,222	1%	2%
Special Contracts	-	0%	0%
Total C&I	1,911,966	100%	36%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
T40	107,436	3%	13%
T50	48,161	1%	22%
T41	460,427	14%	40%
T51	151,120	4%	39%
T42	376,995	11%	82%
T52	1,175,609	35%	98%
Special Contracts	1,058,667	31%	100%
Total C&I	3,378,416	100%	64%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G/T40	820,248	16%
G/T50	214,705	4%
G/T41	1,155,466	22%
G/T51	387,989	7%
G/T42	457,476	9%
G/T52	1,195,830	23%
Special Contracts	1,058,667	20%
Total C&I	5,290,382	100%

Schedule 14

Northern Utilities, Inc.
Storage Analysis

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-10	212,008	-	-	212,008	$ 946,149	$ 4.46	NA	$ -	$ 4.46	$ -	$ 946,149	2.26%	$ 1,784	$ 946,149	$ -
Dec-10	212,008	-	-	212,008	$ 946,149	$ 4.46	NA	$ -	$ 4.46	$ -	$ 946,149	2.26%	$ 1,784	$ 946,149	$ -
Jan-11	212,008	-	8,501	203,507	$ 946,149	$ 4.46	NA	$ -	$ 4.46	$ 37,937	$ 908,213	2.26%	$ 1,749	$ 908,213	$ 37,937
Feb-11	203,507	-	21,743	181,764	$ 908,213	$ 4.46	NA	$ -	$ 4.46	$ 97,036	$ 811,177	2.26%	$ 1,621	$ 811,177	$ 97,036
Mar-11	181,764	-	14,627	167,137	$ 811,177	$ 4.46	NA	$ -	$ 4.46	$ 65,279	$ 745,898	2.26%	$ 1,468	$ 745,898	$ 65,279
Apr-11	167,137	47,381	2,510	212,008	$ 745,898	$ 4.46	$ 4.66	$ 220,690	$ 4.51	$ 11,311	$ 955,278	2.26%	$ 1,604	$ 955,278	$ 11,311
May-11	-	53,599	-	53,599	$ -	NA	$ 5.07	$ 271,922	$ 5.07	$ -	$ 271,922	2.26%	$ 256	$ 271,922	$ -
Jun-11	53,599	51,870	-	105,469	$ 271,922	$ 5.07	$ 5.10	$ 264,402	$ 5.09	$ -	$ 536,324	2.26%	$ 762	$ 536,324	$ -
Jul-11	105,469	53,599	-	159,068	$ 536,324	$ 5.09	$ 5.15	$ 276,195	$ 5.11	$ -	$ 812,519	2.26%	$ 1,272	$ 812,519	$ -
Aug-11	159,068	42,340	-	201,408	$ 812,519	$ 5.11	$ 5.18	$ 219,307	$ 5.12	$ -	$ 1,031,826	2.26%	$ 1,739	$ 1,031,826	$ -
Sep-11	201,408	-	-	201,408	$ 1,031,826	$ 5.12	NA	$ -	$ 5.12	$ -	$ 1,031,826	2.26%	$ 1,946	$ 1,031,826	$ -
Oct-11	201,408	-	-	201,408	$ 1,031,826	$ 5.12	NA	$ -	$ 5.12	$ -	$ 1,031,826	2.26%	$ 1,946	$ 1,031,826	$ -

Washington 10 Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-10	2,779,500	-	-	2,779,500	$11,684,462	$ 4.20	NA	$ -	$ 4.20	$ -	$ 11,684,462	2.26%		$ 11,684,462	$ -
Dec-10	2,779,500	-	405,109	2,374,391	$11,684,462	$ 4.20	NA	$ -	$ 4.20	$1,702,997	$ 9,981,465	2.26%		$ 9,981,465	$1,702,997
Jan-11	2,374,391	-	852,241	1,522,150	$ 9,981,465	$ 4.20	NA	$ -	$ 4.20	$3,582,652	$ 6,398,813	2.26%		$ 6,398,813	$3,582,652
Feb-11	1,522,150	-	728,039	794,110	$ 6,398,813	$ 4.20	NA	$ -	$ 4.20	$3,060,532	$ 3,338,281	2.26%		$ 3,338,281	$3,060,532
Mar-11	794,110	-	516,160	277,950	$ 3,338,281	$ 4.20	NA	$ -	$ 4.20	$2,169,835	$ 1,168,446	2.26%		$ 1,168,446	$2,169,835
Apr-11	277,950	-	-	277,950	$ 1,168,446	$ 4.20	NA	$ -	$ 4.20	$ -	$ 1,168,446	2.26%		$ 1,168,446	$ -
May-11	397,068	426,514	-	823,582	$ 1,837,630	$ 4.63	$ 4.86	$2,070,733	$ 4.75	$ -	$ 3,908,364	2.26%		$ 3,908,364	$ -
Jun-11	823,582	412,756	-	1,236,338	$ 3,908,364	$ 4.75	$ 4.89	$2,017,411	$ 4.79	$ -	$ 5,925,774	2.26%		$ 5,925,774	$ -
Jul-11	1,236,338	426,514	-	1,662,852	$ 5,925,774	$ 4.79	$ 4.94	$2,107,284	$ 4.83	$ -	$ 8,033,058	2.26%		$ 8,033,058	$ -
Aug-11	1,662,852	426,514	-	2,089,366	$ 8,033,058	$ 4.83	$ 4.97	$2,118,163	$ 4.86	$ -	$ 10,151,221	2.26%		$ 10,151,221	$ -
Sep-11	2,089,366	412,756	-	2,502,122	$10,151,221	$ 4.86	$ 4.97	$2,051,940	$ 4.88	$ -	$ 12,203,161	2.26%		$ 12,203,161	$ -
Oct-11	2,502,122	277,378	-	2,779,500	$12,203,161	$ 4.88	$ 5.02	$1,392,516	$ 4.89	$ -	$ 13,595,677	2.26%		$ 13,595,677	$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-10	9,669	2,023	1,350	10,341	$ 71,486	$ 7.39	$ 4.77	$ 9,645	$ 6.94	$ 9,368	$ 71,762	2.26%	$ 135	$ 71,762	$ 9,368
Dec-10	10,341	1,395	1,395	10,341	$ 71,762	$ 6.94	$ 4.77	$ 6,652	$ 6.68	$ 9,321	$ 69,094	2.26%	$ 133	$ 69,094	$ 9,321
Jan-11	10,341	361	1,395	9,307	$ 69,094	$ 6.68	$ 4.77	$ 1,721	$ 6.62	$ 9,231	$ 61,584	2.26%	$ 123	$ 61,584	$ 9,231
Feb-11	9,307	1,260	1,260	9,307	$ 61,584	$ 6.62	$ 4.77	$ 6,008	$ 6.40	$ 8,060	$ 59,533	2.26%	$ 114	$ 59,533	$ 8,060
Mar-11	9,307	1,395	1,395	9,307	$ 59,533	$ 6.40	$ 4.77	$ 6,652	$ 6.18	$ 8,627	$ 57,558	2.26%	$ 110	$ 57,558	$ 8,627
Apr-11	9,307	2,665	1,631	10,341	$ 57,558	$ 6.18	$ 4.77	$ 12,707	$ 5.87	$ 9,571	$ 60,694	2.26%	$ 112	$ 60,694	$ 9,571
May-11	9,307	2,429	1,395	10,341	$ 43,220	$ 4.64	$ 6.87	$ 16,681	$ 5.10	$ 7,120	$ 52,781	2.26%	$ 91	$ 52,781	$ 7,120
Jun-11	10,341	1,350	1,350	10,341	$ 52,781	$ 5.10	$ 6.90	$ 9,314	$ 5.31	$ 7,170	$ 54,924	2.26%	$ 102	$ 54,924	$ 7,170
Jul-11	10,341	1,395	1,395	10,341	$ 54,924	$ 5.31	$ 6.95	$ 9,697	$ 5.51	$ 7,681	$ 56,940	2.26%	$ 105	$ 56,940	$ 7,681
Aug-11	10,341	1,395	1,395	10,341	$ 56,940	$ 5.51	$ 6.98	$ 9,732	$ 5.68	$ 7,925	$ 58,747	2.26%	$ 109	$ 58,747	$ 7,925
Sep-11	10,341	1,350	1,350	10,341	$ 58,747	$ 5.68	$ 6.98	$ 9,424	$ 5.83	$ 7,872	$ 60,299	2.26%	$ 112	$ 60,299	$ 7,872
Oct-11	10,341	1,395	1,395	10,341	$ 60,299	$ 5.83	$ 7.03	$ 9,805	$ 5.97	$ 8,333	$ 61,772	2.26%	$ 115	$ 61,772	$ 8,333

Schedule 15

Northern Utilities, Inc.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER PERIOD BALANCE
November 2009 - October 2010

	AMOUNT	
Summer Period Beg. Balance (1)	$91,535	SCHEDULE 2
Less: Reported Collections	($4,942,961)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$4,981,640	SCHEDULE 4
Add: Interest	($5,937)	SCHEDULE 2
Summer Period Ending Balance	$124,276	

(1) Summer period balance as of October 31, 2009, ($536,749) as approved in Order 25,097 in DG 10-050 was adjusted by $628,284 to remove November 2009 costs and collections that were incorrectly included. The amount of $91,535 was the ending balance as of October 31, 2009.

FORM III
Updated March 7, 2011 **Schedule 2**

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
November 2009 - October 2010
Acct 191.10

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
SUMMER PERIOD													
Summer Period Account Beginning Balance	$ 91,535	$ (536,595)	$ (563,865)	$ (578,644)	$ (616,819)	$ (579,200)	$ (66,593)	$ 221,130	$ 212,643	$ 127,080	$ 123,316	$ (45,590)	$ 91,535
Plus: Cost of Firm Gas (Schedule 4)	$ (87,372)	$ -	$ (12,107)	$ (38,480)	$ 39,716	$ 512,862	$ 1,091,441	$ 527,927	$ 533,730	$ 613,501	$ 527,271	$ 1,273,151	$ 4,981,640
Less: Reported Collections (Schedule 3)	$ (540,155)	$ (25,782)	$ (1,127)	$ 1,922	$ (480)	$ 618	$ (803,927)	$ (537,000)	$ (619,752)	$ (617,603)	$ (696,282)	$ (1,103,392)	$ (4,942,961)
Less: Billing Adjustment													
Summer Period Account Ending Balance	$ (535,993)	$ (562,377)	$ (577,098)	$ (615,202)	$ (577,583)	$ (65,720)	$ 220,921	$ 212,057	$ 126,620	$ 122,978	$ (45,695)	$ 124,170	$ 130,213
Month's Average Balance	$ (222,229)	$ (549,486)	$ (570,482)	$ (596,923)	$ (597,201)	$ (322,460)	$ 77,164	$ 216,593	$ 169,632	$ 125,029	$ 38,811	$ 39,290	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (602)	$ (1,488)	$ (1,545)	$ (1,617)	$ (1,617)	$ (873)	$ 209	$ 587	$ 459	$ 339	$ 105	$ 106	$ (5,937)
Summer Period Account Ending Balance w/int	$ (536,595)	$ (563,865)	$ (578,644)	$ (616,819)	$ (579,200)	$ (66,593)	$ 221,130	$ 212,643	$ 127,080	$ 123,316	$ (45,590)	$ 124,276	$ 124,276

FORM III

Updated March 7, 2011 Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

2010 SUMMER PERIOD RECONCILIATION

SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)

November 2009 - October 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Accrued Revenue	$ (984,300)	$ -	$ -	$ -	$ -	$ -	$ 374,909	$ (130,936)	$ 60,573	$ 39,813	$ 62,690	$ 311,677	$ (265,574)
Billed Revenue	$ 1,524,456	$ 25,782	$ 1,127	$ (1,922)	$ 480	$ (618)	$ 429,018	$ 667,936	$ 559,179	$ 577,790	$ 633,592	$ 791,716	$ 5,208,535
Calendarized Revenue	**$ 540,155**	**$ 25,782**	**$ 1,127**	**$ (1,922)**	**$ 480**	**$ (618)**	**$ 803,927**	**$ 537,000**	**$ 619,752**	**$ 617,603**	**$ 696,282**	**$ 1,103,392**	**$ 4,942,961**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2009 - October 2010

Commodity Costs:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total Off Peak
Anadarka Energy	$ 83,446	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,446
Distrigas	$ 5,097	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,097
Emera Energy	$ 117,096	$ -	$ -	$ -	$ 41,634	$ -	$ -	$ 71,921	$ 67,425	$ 72,644	$ 118,540	$ 59,175	$ 548,435
Hess	$ (575)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 257,175	$ 41,925	$ -	$ -	$ 298,525
JP Morgan	$ 391,059	$ -	$ -	$ -	$ -	$ -	$ -	$ 319,361	$ -	$ -	$ -	$ -	$ 710,419
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,723	$ 5,723
South Jersey Resources	$ 156,014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,014
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,003	$ 266,029	$ 320,032
Sprague Energy	$ (649)	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,043	$ 98,308	$ 120,611	$ 126,617	$ 130,682	$ 580,613
Tennessee	$ 3,310	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,996	$ 1,906	$ 2,097	$ 2,156	$ 2,952	$ 14,417
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 152,615	$ -	$ 152,615
Misc Small Suppliers	$ (6,522)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,522)
Subtotal	$ 748,276	$ -	$ -	$ -	$ 41,634	$ -	$ -	$ 498,320	$ 424,813	$ 237,277	$ 453,931	$ 464,561	$ 2,868,814
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 484,957	$ 424,981	$ 242,533	$ 458,734	$ 457,048	$ 746,407	$ 2,814,660
Commodity Cost Reversals	$ (835,648)	$ -	$ -	$ -	$ -	$ -	$ -	$ (484,957)	$ (424,981)	$ (242,533)	$ (458,734)	$ (457,048)	$ (2,903,901)
Subtotal	$ (87,372)	$ -	$ -	$ -	$ 41,634	$ -	$ 484,957	$ 438,344	$ 242,365	$ 453,479	$ 452,245	$ 753,920	$ 2,779,573
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (509)	$ (395)	$ 3,154	$ 185	$ 166	$ (679)	$ 1,922
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 289,307	$ 233,654	$ 224,568	$ (11,661)	$ (853)	$ 127,328	$ 862,344
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,317)	$ (8,046)	$ (8,805)	$ (8,512)	$ (6,921)	$ (40,600)
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ (14,135)	$ -	$ (65,099)	$ (330,547)	$ (54,378)	$ -	$ (98,471)	$ (562,630)
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,774)	$ 115	$ (2,108)	$ (2,824)	$ (4,551)	$ (560)	$ (11,701)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,967	$ 6,228	$ 4,643	$ 5,346	$ 5,274	$ 4,944	$ 32,402
Transportation Charges	$ -	$ -	$ (12,107)	$ (38,480)	$ (1,918)	$ 526,997	$ -	$ 1,424	$ (57,059)	$ (3,983)	$ (1,504)	$ (25,672)	$ 387,699
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,387	$ 2,144	$ 2,131	$ 1,719	$ 1,957	$ 314,303	$ 527,641
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ -	$ -	$ (12,107)	$ (38,480)	$ (1,918)	$ 512,862	$ 498,378	$ 169,755	$ (163,264)	$ (74,400)	$ (8,022)	$ 314,273	$ 1,197,077
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (75,967)	$ (337,983)	$ (63,183)	$ (8,512)	$ (105,392)	$ (81,484)	$ (672,521)
Sales for Resale Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,967	$ 337,983	$ 63,183	$ 8,512	$ 105,392	$ 591,036
Total Commodity Costs	**$ (87,372)**	**$ -**	**$ (12,107)**	**$ (38,480)**	**$ 39,716**	**$ 512,862**	**$ 907,368**	**$ 346,083**	**$ 353,901**	**$ 433,749**	**$ 347,344**	**$ 1,092,101**	**$ 3,895,166**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2009 - October 2010

Demand Costs	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total Off Peak
Forecasted Summer Demand Costs (DG 10-050)	$ -	$ -	$ -	$ -	$ -	$ -	$ 176,337	$ 176,337	$ 176,337	$ 176,337	$ 176,337	$ 176,337	$ 1,058,022
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,736	$ 5,506	$ 3,492	$ 3,414	$ 3,590	$ 4,713	$ 28,452
Total Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 184,073	$ 181,843	$ 179,829	$ 179,751	$ 179,927	$ 181,050	$ 1,086,474
Total Gas Costs	$ (87,372)	$ -	$ (12,107)	$ (38,480)	$ 39,716	$ 512,862	$ 1,091,441	$ 527,927	$ 533,730	$ 613,501	$ 527,271	$ 1,273,151	$ 4,981,640

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2009 - October 2010

New Hampshire	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Throughput IN													
BTU Factor	1.037	1.04053	1.042	1.044	1.039	1.03975	1.038	1.039	1.033	1.036	1.039	1.041	
GST Meter Throughput (M	528,094	880,611	977,063	812,599	665,946	416,782	312,869	265,598	249,025	269,606	273,645	427,825	6,079,663
Salem Meter (MCF)	27,009	56,707	61,967	49,058	34,966	18,950	12,766	9,904	9,385	9,959	10,496	18,586	319,753
GST Meter Throughput (I	547,633	916,302	1,018,100	848,353	691,918	433,349	324,758	275,956	257,243	279,312	284,317	445,366	6,322,608
Salem Meter (DTH)	28,008	59,005	64,570	51,217	36,330	19,703	13,251	10,290	9,695	10,318	10,905	19,348	332,640
LNG/Propane													-
Total Throughput	575,642	975,307	1,082,669	899,570	728,248	453,052	338,009	286,247	266,938	289,629	295,222	464,714	6,655,247
Throughput OUT													
Residential Gas													
Charged	114,181	153,165	320,901	266,164	208,617	154,085	89,805	48,593	37,542	31,398	35,343	45,287	1,505,081
Uncharged Current	71,699	132,901	139,568	126,626	96,640	71,183	24,753	17,120	17,902	18,960	24,555	50,075	791,981
Uncharged Prior	(47,772)	(71,699)	(132,901)	(139,568)	(126,626)	(96,640)	(71,183)	(24,753)	(17,120)	(17,902)	(18,960)	(24,555)	(789,678)
Total Residential Gas	**138,108**	**214,367**	**327,568**	**253,222**	**178,631**	**128,628**	**43,375**	**40,960**	**38,324**	**32,457**	**40,938**	**70,806**	1,507,384
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	134,296	213,173	371,131	308,200	236,761	162,214	100,468	56,259	50,821	48,982	52,749	63,675	1,798,729
Uncharged Current	81,951	157,742	163,939	151,115	114,042	75,149	33,010	24,405	24,409	28,929	31,853	48,382	934,925
Uncharged Prior	(56,218)	(81,951)	(157,742)	(163,939)	(151,115)	(114,042)	(75,149)	(33,010)	(24,405)	(24,409)	(28,929)	(31,853)	(942,761)
Total C/I Gas	**160,029**	**288,963**	**377,329**	**295,376**	**199,688**	**123,321**	**58,329**	**47,654**	**50,825**	**53,502**	**55,673**	**80,204**	1,790,894
Transportation													
Charged	274,355	362,827	418,102	374,369	348,655	274,469	210,279	200,287	183,338	202,932	206,761	246,364	3,302,738
Uncharged Current	110,691	186,138	147,132	139,598	124,303	85,504	55,335	55,311	49,937	65,560	74,219	115,721	1,209,449
Uncharged Prior	(101,472)	(110,691)	(186,138)	(147,132)	(139,598)	(124,303)	(85,504)	(55,335)	(55,311)	(49,937)	(65,560)	(74,219)	(1,195,200)
Total Transportation	**283,574**	**438,274**	**379,095**	**366,836**	**333,359**	**235,670**	**180,110**	**200,263**	**177,964**	**218,555**	**215,420**	**287,866**	**3,316,987**
Company Use	**38**	**81**	**137**	**118**	**76**	**49**	**25**	**7**	**2**	**2**	**6**	**17**	**555**
Total Throughput OUT	**581,750**	**941,685**	**1,084,129**	**915,550**	**711,754**	**487,669**	**281,838**	**288,884**	**267,115**	**304,515**	**312,037**	**438,893**	**6,615,819**
Total Throughput IN	**575,642**	**975,307**	**1,082,669**	**899,570**	**728,248**	**453,052**	**338,009**	**286,247**	**266,938**	**289,629**	**295,222**	**464,714**	**6,655,247**
Difference IN/OUT	(6,108)	33,622	(1,460)	(15,980)	16,494	(34,616)	56,171	(2,637)	(178)	(14,885)	(16,815)	25,821	39,428
%													0.59%

Updated March 7, 2011 Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER PERIOD WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2009 - October 2010

SUMMER PERIOD - Acct 182.21

		BEGINNING BALANCE	WORKING CAP ALLOWANCE	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2009	$	(7,039)	(49)	0.0564%	(1,189)	(1,238)	(8,277)	(7,658)	3.25%	(21)	(8,297)
December	$	(8,297)	0	0.0564%	(57)	(57)	(8,354)	(8,326)	3.25%	(23)	(8,377)
January 2010	$	(8,377)	(7)	0.0564%	(3)	(10)	(8,387)	(8,382)	3.25%	(23)	(8,410)
February	$	(8,410)	(22)	0.0564%	5	(16)	(8,426)	(8,418)	3.25%	(23)	(8,449)
March	$	(8,449)	22	0.0564%	(1)	22	(8,427)	(8,438)	3.25%	(23)	(8,450)
April	$	(8,450)	289	0.0564%	2	291	(8,159)	(8,305)	3.25%	(22)	(8,182)
May	$	(8,182)	616	0.0564%	(348)	267	(7,914)	(8,048)	3.25%	(22)	(7,936)
June	$	(7,936)	298	0.0564%	(226)	72	(7,864)	(7,900)	3.25%	(21)	(7,885)
July	$	(7,885)	301	0.0564%	(220)	82	(7,804)	(7,845)	3.25%	(21)	(7,825)
August	$	(7,825)	346	0.0564%	(244)	102	(7,723)	(7,774)	3.25%	(21)	(7,744)
September	$	(7,744)	297	0.0564%	(276)	21	(7,723)	(7,733)	3.25%	(21)	(7,744)
October	$	(7,744)	718	0.0564%	(448)	270	(7,473)	(7,608)	3.25%	(21)	(7,494)

Updated March 7, 2011 Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2009 - October 2010

SUMMER PERIOD - Acct 182.22

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2009	(1,487)	(393)	0.45%	(2,998)	(3,391)	(4,878)	(3,183)	3.25%	(9)	(4,887)
December	(4,887)	0	0.45%	(144)	(144)	(5,031)	(4,959)	3.25%	(13)	(5,044)
January 2010	(5,044)	(55)	0.45%	(8)	(63)	(5,107)	(5,075)	3.25%	(14)	(5,121)
February	(5,121)	(173)	0.45%	13	(160)	(5,280)	(5,200)	3.25%	(14)	(5,294)
March	(5,294)	179	0.45%	(2)	177	(5,118)	(5,206)	3.25%	(14)	(5,132)
April	(5,132)	2,309	0.45%	4	2,314	(2,818)	(3,975)	3.25%	(11)	(2,829)
May	(2,829)	4,914	0.45%	(2,828)	2,086	(743)	(1,786)	3.25%	(5)	(747)
June	(747)	2,377	0.45%	(2,045)	332	(416)	(581)	3.25%	(2)	(417)
July	(417)	2,403	0.45%	(2,043)	361	(56)	(237)	3.25%	(1)	(57)
August	(57)	2,762	0.45%	(1,978)	784	727	335	3.25%	1	728
September	728	2,374	0.45%	(2,211)	163	891	810	3.25%	2	893
October	893	5,732	0.45%	(3,472)	2,261	3,154	2,024	3.25%	5	3,159

(1) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER PERIOD 2010

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
Forecast Calendar Month Sales	227,554	161,959	102,702	100,429	105,605	138,634	836,884
Actual Sales	190,273	104,852	88,363	80,380	88,092	108,961	660,921
Difference	(37,281)	(57,107)	(14,339)	(20,049)	(17,513)	(29,673)	(175,963)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	205,158	124,346	94,820	82,366	92,083	120,558	719,331
Actual Sales	190,273	104,852	88,363	80,380	88,092	108,961	660,921
Weather Variance	14,885	19,494	6,457	1,986	3,991	11,597	58,410
Total Variance Excluding Weather (excl weather effect)	(22,396)	(37,613)	(7,882)	(18,063)	(13,522)	(18,076)	(117,553)
Variance-difference due to meter count							(11,505)
-difference in load pattern							(144,558)
SALES							(156,063)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER PERIOD 2010

	NORMAL MMBtu			METERS		
	2010 Forecast	2010 Actual	Difference	2010 Forecast	2010 Actual	Difference
Res Heat	333,305	289,852	(43,453)	124,623	122,064	(2,559)
Res General	11,312	11,795	483	9,544	9,881	337
Total Res	344,617	301,647	(42,970)	134,167	131,945	(2,222)
G-40	123,056	87,056	(36,000)	25,158	24,828	(330)
G-50	81,583	72,423	(9,160)	5,904	5,625	(279)
G-41	143,584	111,885	(31,699)	2,280	2,304	24
G-51	122,918	95,626	(27,292)	1,038	999	(39)
G-42	17,929	18,308	379	72	113	41
G-52	14,174	4,853	(9,321)	36	19	(17)
Total C & I	503,244	390,151	(113,093)	34,488	33,888	(600)
Total Company	847,861	691,798	(156,063)	168,655	165,833	(2,822)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2010 Forecast	2010 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.67	2.37	(0.30)	(6,844)	(36,609)	(43,453)	-13.04%
Res General	1.19	1.19	0.01	399	84	483	4.27%
Total Res	3.86	3.57	(0.29)	(6,445)	(36,525)	(42,970)	-12.47%
G-40	4.89	3.51	(1.38)	(1,614)	(34,386)	(36,000)	-29.25%
G-50	13.82	12.88	(0.94)	(3,855)	(5,305)	(9,160)	-11.23%
G-41	62.98	48.56	(14.41)	1,511	(33,210)	(31,699)	-22.08%
G-51	118.42	95.72	(22.70)	(4,618)	(22,674)	(27,292)	-22.20%
G-42	249.01	162.02	(87.00)	10,210	(9,831)	379	2.11%
G-52	393.72	255.42	(138.30)	(6,693)	(2,628)	(9,321)	-65.76%
Total C & I	14.59	11.51	(3.08)	(5,060)	(108,033)	(113,093)	-22.47%
Total Company	5.03	4.17	(0.86)	(11,505)	(144,558)	(156,063)	-18.41%

Schedule 16

Northern Utilities, Inc.

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 17

Unitil
Northern Utilities, Inc.

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 18

Northern Utilities, Inc.

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 19

Northern Utilities, Inc.

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 20

Northern Utilities, Inc.

		Off-Peak Season		Peak Season								
		May-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Peak Season	Off-Peak Season	Total Contracts
	*Ceilings**	*8.263*	*8.905*	*9.903*	*9.375*	*9.572*	*9.499*	*9.197*	*8.121*			
Scheduled Purchases	04/27/11	1	2	1	1	3	2	2	1	10	3	13
	05/26/11	1	1	1	2	2	2	2	1	10	2	12
	06/28/11	1	1	1	2	2	2	2	1	10	2	12
	07/27/11	1	1	2	1	3	1	2	1	10	2	12
	08/29/11	1	2	1	2	2	2	2	1	10	3	13
	09/28/11	1	1	1	2	2	2	2	2	11	2	13
	10/27/11	2	1	1	2	3	2	1	1	10	3	13
	11/28/11	1	1	1	2	2	2	2	1	10	2	12
	12/28/11	1	2	1	2	2	2	2	1	10	3	13
	01/27/12	1	1	1	1	3	2	2	1	10	2	12
	02/27/12	1	1	1	2	2	2	2	1	10	2	12
	03/28/12	1	1	1	2	2	2	2	2	11	2	13
Make-Up Purchases (white area) Scheduled Sales (gray area)	04/26/12	-13								0	-13	-13
	05/29/12									0	0	0
	06/27/12									0	0	0
	07/27/12									0	0	0
	08/29/12									0	0	0
	09/26/12		-15							0	-15	-15
	10/29/12			-13						-13	0	-13
	11/28/12				-21					-21	0	-21
	12/27/12					-28				-28	0	-28
	01/29/13						-23			-23	0	-23
	02/26/13							-23		-23	0	-23
	03/26/13								-14	-14	0	-14
	Scheduled	13	15	13	21	28	23	23	14	122	28	150
	check	0	0	0	0	0	0	0	0	0	0	0

*Note: Price Ceilings reflect 2011-12 levels and will be updated for 2012-13 with the Cost of Gas update in mid-April.

Northern Utilities, Inc.
3-Year Outlook for Annual Hedging Plans

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts	City-Gate Volumes	Percent of Sendout	Futures Contracts	City-Gate Volumes	Percent of Sendout	Futures Contracts
	SUMMER PERIOD	SUMMER 2012			SUMMER 2013			SUMMER 2014		
1	Sendout Requirement (May, Oct)	705,984			750,964			797,089		
2	Financial Hedge Volume	280,000	40%	28	300,000	40%	30	320,000	40%	32
	WINTER PERIOD	WINTER 2012-13			WINTER 2013-14			WINTER 2014-15		
3	Sendout Requirement	5,725,986			5,928,893			6,135,281		
4	Washington 10 Storage	2,543,619	44%		2,543,619	43%		2,543,619	41%	
5	Tennessee Storage	240,755	4%		240,755	4%		240,755	4%	
6	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
7	Financial Hedge Volume	1,220,000	21%	122	1,370,000	23%	137	1,510,000	25%	151
8	Total Hedged Volume	4,004,374	70%		4,154,374	70%		4,294,374	70%	
	HEDGE PLAN YEAR	PLAN YEAR 2012-13			PLAN YEAR 2013-14			PLAN YEAR 2014-15		
9	Financial Hedge Volume	1,500,000	23%	150	1,670,000	25%	167	1,830,000	26%	183

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts
1				
2	SUMMER PERIOD		SUMMER 2011	
3				
4	Sendout Requirement (May, Oct)	656,883		
5	Currently Held Financial Contracts	210,000	32%	21
6	Planned Financial Contracts	90,000	14%	9
7	Total Hedged Volume	300,000	46%	30
8	Target Hedged Volume	260,000	40%	26
9	Projected Position Relative to Target Long/(Short)	40,000	6%	4
10				
11	WINTER PERIOD		WINTER 2011-12	
12				
13	Sendout Requirement	5,563,669		
14	Washington 10 Storage	2,543,619	46%	
15	Tennessee Storage	240,755	4%	
16	Fixed Price Physical Contracts	0	0%	
17	Currently Held Financial Contracts	640,000	12%	64
18	Planned Financial Contracts	320,000	6%	32
19	Total Hedged Volume	3,744,374	67%	
20	Target Financial Hedge	3,890,000	70%	
21	Projected Position Relative to Target Long/(Short)	-150,000	-3%	-15

Schedule 21

Northern Utilities, Inc.

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 6,979,327
Storage Demand	$ 26,009,867
Peaking Demand	$ 6,160,974
Subtotal Demand	$ 39,150,168
Litigation Expense - PNGTS Invoices from 9/1/2009 - 8/13/2010	$ 376,840
Capacity Release (Credit)	$ (424,530)
Asset Management (Credit)	$ (2,507,000)
Total Net Demand Costs	$ 36,595,478

Proportional Responsibility (PR) Allocators

Allocation of Product and Pipeline Demand Costs (including Injections) to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
Rank	4	2	1	6	3	5	8	9	12	11	10	7	
% Max Month	96.85%	100.00%	100.00%	90.32%	98.51%	94.19%	86.61%	60.01%	51.03%	54.37%	58.89%	89.57%	
PR	0.66%	0.75%	0.00%	0.13%	0.55%	0.77%	3.32%	0.12%	4.25%	0.30%	0.45%	0.42%	11.74%
CumPR	10.44%	11.74%	11.74%	9.01%	11.00%	9.78%	8.46%	5.13%	4.25%	4.56%	5.01%	8.88%	100.00%
Product and Pipeline Demand Costs	$ 728,959	$ 819,550	$ 819,550	$ 628,551	$ 767,521	$ 682,593	$ 590,239	$ 358,201	$ 296,825	$ 318,012	$ 349,555	$ 619,771	$ 6,979,327

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	5,234	554,104	556,770	575,329	574,118	556,770	551,826	3,374,152
Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	47.0%	56.2%	61.0%	59.4%	56.7%	46.0%	32.3%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 5,214	$ 277,309	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 285,364	$ 1,337,337

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	135,581	686,913	1,016,879	728,568	633,976	190,867	24,831	-	-	-	-	17,189	3,434,803
Rank	6	3	1	2	4	5	7	9	9	9	9	8	
% Max Month	13.33%	67.55%	100.00%	71.65%	62.35%	18.77%	2.44%	0.00%	0.00%	0.00%	0.00%	1.69%	
PR	1.82%	1.74%	28.35%	2.05%	10.89%	1.09%	0.11%	0.00%	0.00%	0.00%	0.00%	0.21%	46.25%
CumPR	2.13%	15.85%	46.25%	17.90%	14.12%	3.22%	0.32%	0.00%	0.00%	0.00%	0.00%	0.21%	100.00%
Storage Demand Costs	$ 555,014	$ 4,122,650	$ 12,029,843	$ 4,655,382	$ 3,671,308	$ 837,833	$ 82,881	$ -	$ -	$ -	$ -	$ 54,956	$ 26,009,867
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 5,214	$ 277,309	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 285,364	$ 1,337,337
TOTAL	$ 555,014	$ 4,122,650	$ 12,029,843	$ 4,655,382	$ 3,671,308	$ 843,047	$ 360,190	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 340,320	$ 27,347,204

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	134,340	128,242	199,339	162,905	111,881	139,911	16,142	1,350	1,395	1,395	1,350	3,873	902,124
Rank	4	5	1	2	6	3	7	12	10	9	11	8	
% Max Month	67.39%	64.33%	100.00%	81.72%	56.13%	70.19%	8.10%	0.68%	0.70%	0.70%	0.68%	1.94%	
PR	0.76%	1.64%	18.28%	5.77%	8.00%	0.93%	0.88%	0.06%	0.00%	0.00%	0.00%	0.16%	36.48%
CumPR	11.50%	10.74%	36.48%	18.20%	9.10%	12.44%	1.09%	0.06%	0.06%	0.06%	0.06%	0.21%	100.00%
Peaking Demand Costs	$ 708,782	$ 661,665	$ 2,247,566	$ 1,121,516	$ 560,532	$ 766,178	$ 67,359	$ 3,477	$ 3,616	$ 3,616	$ 3,477	$ 13,189	$ 6,160,974

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

LN	Description	Source
1		
2		
3	Pipeline Demand	Schedule 5
4	Storage Demand	Schedule 5
5	Peaking Demand	Schedule 5
6	Subtotal Demand	Sum LN 3 : LN 5
7		
8	Capacity Release (Credit)	Schedule 5
9	Asset Management (Credit)	Schedule 5
10	Total Net Demand Costs	Sum LN 6 : LN 9
11		
12		
13	**Proportional Responsibility (PR) Allocators**	
14		
15	**Allocation of Product and Pipeline Demand Costs (including Injections) to Months**	
16		
17	Design Year Pipeline Sendout	Company Analysis
18	Rank	LN 17 Ranking
19	% Max Month	LN 17 / LN 17 MAX
20	PR	The difference between LN 19 for the month and LN 19 for next highest rank
21	CumPR	Cumulative Values, LN 20
22	Product and Pipeline Demand Costs	LN 21 * LN 3
23		
24	**Allocation of Storage Injection Fees to Months**	
25		
26	Storage Injection Volume	Company Analysis
27	Design Year Pipeline Sendout	LN 17
28	% of Deliveries Injected	LN 26 / Sum (LN 26 : LN 27)
29	Injection Fees	LN 28 * LN 22
30		
31	**Allocation of Storage Demand Costs to Months**	
32		
33	Design Year Storage	Company Analysis
34	Rank	LN 33 Ranking
35	% Max Month	LN 33 / LN 33 MAX
36	PR	The difference between LN 35 for the month and LN 35 for next highest rank
37	CumPR	Cumulative Values, LN 36
38	Storage Demand Costs	LN 37 * LN 4
39	Plus Injection Fees	LN 29
40	TOTAL	LN 38 + LN 39
41		
42	**Allocation of Peaking Demand Costs to Months**	
43		
44	Design Year Peaking Volumes	Company Analysis
45	Rank	Rank LN 44
46	% Max Month	LN 44 / LN 44 MAX
47	PR	The difference between LN 46 for the month and LN 46 for next highest rank
48	CumPR	Cumulative Values, LN 47
49	Peaking Demand Costs	LN 48 * LN 5

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
50	Pipeline & Product Demand	$ 728,959	$ 819,550	$ 819,550	$ 628,551	$ 767,521	$ 682,593	$ 590,239	$ 358,201	$ 296,825	$ 318,012	$ 349,555	$ 619,771	$ 6,979,327
51	Storage Incld Inj Fees	$ 555,014	$ 4,122,650	$ 12,029,843	$ 4,655,382	$ 3,671,308	$ 843,047	$ 360,190	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 340,320	$ 27,347,204
52	Peaking	$ 708,782	$ 661,665	$ 2,247,566	$ 1,121,516	$ 560,532	$ 766,178	$ 67,359	$ 3,477	$ 3,616	$ 3,616	$ 3,477	$ 13,189	$ 6,160,974
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (5,214)	$ (277,309)	$ (201,445)	$ (180,942)	$ (188,867)	$ (198,195)	$ (285,364)	$ (1,337,337)
54	Less: Capacity Release	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (424,530)
55	Less: Asset Mgmt net of Current PNGTS	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,130,160)
56	Total Demand	$ 1,552,822	$ 5,163,932	$ 14,657,027	$ 5,965,517	$ 4,559,428	$1,931,577	$ 740,479	$ 361,678	$ 300,441	$ 321,628	$ 353,032	$ 687,917	$ 36,595,478

57

58 **Capacity Cost Allocator based on Design Year Firm Sendout**

59		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
60	**Therms**													
61	Maine	512,441	802,081	984,724	779,373	729,594	512,543	334,300	199,982	211,643	224,651	216,214	361,107	5,868,653
62	New Hampshire	451,012	725,852	941,537	754,644	718,372	492,061	327,795	231,682	156,234	167,196	207,705	302,779	5,476,869
63	Total	963,453	1,527,933	1,926,261	1,534,017	1,447,966	1,004,604	662,095	431,664	367,877	391,847	423,919	663,886	11,345,522

64	**Percentage of Total**	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
65	Maine	53.19%	52.49%	51.12%	50.81%	50.39%	51.02%	50.49%	46.33%	57.53%	57.33%	51.00%	54.39%	51.36%
66	New Hampshire	46.81%	47.51%	48.88%	49.19%	49.61%	48.98%	49.51%	53.67%	42.47%	42.67%	49.00%	45.61%	48.64%
67	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

68

69 **Allocation of Demand Costs by Division**

70	Maine	$825,914	$2,710,781	$7,492,819	$3,030,842	$2,297,382	$985,479	$373,877	$167,559	$172,846	$184,394	$180,059	$374,178	$18,796,131
71	New Hampshire	$726,908	$2,453,151	$7,164,207	$2,934,675	$2,262,046	$946,098	$366,602	$194,119	$127,595	$137,235	$172,973	$313,739	$17,799,347
72	Total	$ 1,552,822	$ 5,163,932	$ 14,657,027	$ 5,965,517	$ 4,559,428	$ 1,931,577	$ 740,479	$ 361,678	$ 300,441	$ 321,628	$ 353,032	$ 687,917	$ 36,595,478

73 **Detailed Allocation of Demand Costs by Division**

74	**Maine**	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	
75	Pipeline & Product Demand	$ 387,718	$ 430,219	$ 418,962	$ 319,342	$ 386,735	$ 348,255	$ 298,019	$ 165,948	$ 170,766	$ 182,320	$ 178,286	$ 337,112	$ 3,623,682	51.92%
76	Storage Incld Injection Fees	$ 295,200	$ 2,164,165	$ 6,149,777	$ 2,365,215	$ 1,849,880	$ 430,117	$ 181,865	$ 93,326	$ 104,098	$ 108,280	$ 101,086	$ 185,110	$ 14,028,120	51.30%
77	Peaking	$ 376,987	$ 347,338	$ 1,148,978	$ 569,798	$ 282,438	$ 390,900	$ 34,010	$ 1,611	$ 2,080	$ 2,073	$ 1,773	$ 7,174	$ 3,165,160	51.37%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,660)	$ (140,017)	$ (93,326)	$ (104,098)	$ (108,280)	$ (101,086)	$ (155,218)	$ (704,685)	
79	Capacity Release (Credit)	$ (45,160)	$ (44,571)	$ (43,405)	$ (43,137)	$ (42,782)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (219,055)	51.60%
80	Asset Management - PNGTS (Credit)	$ (188,831)	$ (186,370)	$ (181,493)	$ (180,375)	$ (178,889)	$ (181,132)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,097,091)	51.50%
81	**Total Allocated Demand**	$ 825,914	$ 2,710,781	$ 7,492,819	$ 3,030,842	$ 2,297,382	$ 985,479	$ 373,877	$ 167,559	$ 172,846	$ 184,394	$ 180,059	$ 374,178	$ 18,796,131	51.36%

82

83	**New Hampshire**	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	
84	Pipeline & Product Demand	$ 341,241	$ 389,331	$ 400,588	$ 309,209	$ 380,786	$ 334,338	$ 292,220	$ 192,253	$ 126,059	$ 135,692	$ 171,269	$ 282,660	$ 3,355,645	48.08%
85	Storage Incld Injection Fees	$ 259,813	$ 1,958,485	$ 5,880,066	$ 2,290,168	$ 1,821,427	$ 412,929	$ 178,326	$ 108,119	$ 76,844	$ 80,587	$ 97,108	$ 155,210	$ 13,319,084	48.70%
86	Peaking	$ 331,795	$ 314,327	$ 1,098,587	$ 551,718	$ 278,094	$ 375,279	$ 33,348	$ 1,866	$ 1,536	$ 1,543	$ 1,704	$ 6,015	$ 2,995,813	48.63%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,554)	$ (137,292)	$ (108,119)	$ (76,844)	$ (80,587)	$ (97,108)	$ (130,146)	$ (632,652)	
88	Capacity Release	$ (39,746)	$ (40,335)	$ (41,501)	$ (41,769)	$ (42,124)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (205,475)	48.40%
89	Asset Management - PNGTS (Credit)	$ (166,195)	$ (168,657)	$ (173,533)	$ (174,652)	$ (176,138)	$ (173,894)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,033,069)	48.50%
90	**Total Allocated Demand**	$ 726,908	$ 2,453,151	$ 7,164,207	$ 2,934,675	$ 2,262,046	$ 946,098	$ 366,602	$ 194,119	$ 127,595	$ 137,235	$ 172,973	$ 313,739	$ 17,799,347	48.64%

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

50	Pipeline & Product Demand	LN 22
51	Storage	LN 40
52	Peaking	LN 49
53	Less: Injection Fees	-(LN 29)
54	Less: Capacity Release	LN 8 / 5
55	Less: Asset Management	(LN 9 + LN 7) / 6
56	Total Demand	Sum (LN 50 : LN 55)
57		
58	**Capacity Cost Allocator based on Design Year Firm Sendout**	
59		
60	**Therms**	
61	Maine	Company Analysis
62	New Hampshire	Company Analysis
63	Total	LN 61 + LN 62
64	**Percentage of Total**	
65	Maine	LN 61 / LN 63
66	New Hampshire	LN 62 / LN 63
67	Total	LN 65 + LN 66
68		
69	**Allocation of Demand Costs by Division**	
70	Maine	LN 56 * LN 65
71	New Hampshire	LN 56 * LN 66
72	Total	LN 70 + LN 71
73	**Detailed Allocation of Demand Costs by Division**	
74	**Maine**	
75	Pipeline & Product Demand	LN 50 * LN 65
76	Storage	LN 51 * LN 65
77	Peaking	LN 52 * LN 65
78	Injection Fees	LN 53 * LN 65
79	Capacity Release (Credit)	LN 54 * LN 65
80	Asset Management (Credit)	LN 55 * LN 65
81	**Total Allocated Demand**	Sum (LN 75 : LN 80)
82		
83	**New Hampshire**	
84	Pipeline & Product Demand	LN 50 * LN 66
85	Storage	LN 51 * LN 66
86	Peaking	LN 52 * LN 66
87	Injection Fees	LN 53 * LN 66
88	Capacity Release	LN 54 * LN 66
89	Asset Management (Credit)	LN 55 * LN 66
90	**Total Allocated Demand**	Sum (LN 84 : LN 89)

Schedule 22

Unitil
Northern Utilities, Inc.

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	SUMMER
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	304,244	188,838	139,235	176,289	216,266	349,849	3,621,221	1,374,721
3	Total Storage	0	0	0	0	0	0	2,488,619	0
4	Total Peaking	1,395	1,350	1,395	1,395	1,350	1,395	629,141	8,280
5	Subtotal	305,639	190,188	140,630	177,684	217,616	351,244	6,738,982	1,383,001
6	Less Interruptible - Maine	0	0	0	0	0	0	0	0
7	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
8	Total Firm Supply	305,639	190,188	140,630	177,684	217,616	351,244	6,738,982	1,383,001
9	Total Firm Pipeline Sendout	304,244	188,838	139,235	176,289	216,266	349,849	3,621,221	1,374,721
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 1,549,919	$ 961,254	$ 715,227	$ 911,185	$ 1,119,926	$ 1,837,342	$ 17,695,161	$ 7,094,853
12	NYMEX Price Used for Forecast	$4.707	$4.739	$4.791	$4.816	$4.821	$4.869		
13	NYMEX Price Used for Update	$3.950	$4.015	$4.084	$4.116	$4.128	$4.176		
14	Increase/(Decrease) NYMEX Price	-$0.757	-$0.724	-$0.707	-$0.700	-$0.693	-$0.693		
15	Increase/(Decrease) in Pipeline Costs	$ (230,313)	$ (136,719)	$ (98,439)	$ (123,402)	$ (149,872)	$ (242,445)		
16	Total Updated Pipeline Costs	$ 1,319,606	$ 824,535	$ 616,788	$ 787,783	$ 970,054	$ 1,594,896	$ 16,713,970	$ 6,113,662
17									
18	Total Pipeline	$ 1,319,606	$ 824,535	$ 616,788	$ 787,783	$ 970,054	$ 1,594,896	$ 16,713,970	$ 6,113,662
19	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,895,622	$ -
20	Total Peaking	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 2,457,873	$ 46,101
21	Subtotal	$ 1,326,726	$ 831,705	$ 624,469	$ 795,708	$ 977,926	$ 1,603,229	$ 30,067,466	$ 6,159,763
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	14	-	-	-	-	9	61	23
26	Average Purchase Price	$ 4.712	$ -	$ -	$ -	$ -	$ 4.944		
27	NYMEX Price Used for Forecast	$ 4.707	$ 4.739	$ 4.791	$ 4.816	$ 4.821	$ 4.869		
28	NYMEX Price Used for Update	$ 3.950	$ 4.015	$ 4.084	$ 4.116	$ 4.128	$ 4.176		
29	Increase/(Decrease) NYMEX Price	$ (0.757)	$ (0.724)	$ (0.707)	$ (0.700)	$ (0.693)	$ (0.693)		
30	Futures Hedging (Gain)/Loss - Allocate	$ 106,680	$ -	$ -	$ -	$ -	$ 69,120	$ 1,061,460	$ 175,800
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	28	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 4.707	$ 4.739	$ 4.791	$ 4.816	$ 4.821	$ 4.869		
35	NYMEX Price Used for Update	$ 3.950	$ 4.015	$ 4.084	$ 4.116	$ 4.128	$ 4.176		
36	Increase/(Decrease) NYMEX Price	$ (0.757)	$ (0.724)	$ (0.707)	$ (0.700)	$ (0.693)	$ (0.693)		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ 654,620	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 1,319,606	$ 824,535	$ 616,788	$ 787,783	$ 970,054	$ 1,594,896	$ 16,713,970	$ 6,113,662
41	Average Supply Cost ($/MMBtu)	$ 4.337	$ 4.366	$ 4.430	$ 4.469	$ 4.485	$ 4.559		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 1,319,606	$ 824,535	$ 616,788	$ 787,783	$ 970,054	$ 1,594,896	$ 16,713,970	$ 6,113,662
46	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,895,622	$ -
47	Total Peaking	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 2,457,873	$ 46,101
48	Firm Sales Variable Costs Excld Hedge	$ 1,326,726	$ 831,705	$ 624,469	$ 795,708	$ 977,926	$ 1,603,229	$ 30,067,466	$ 6,159,763
49	Plus Hedging (Gain)/Loss	$ 106,680	$ -	$ -	$ -	$ -	$ 69,120	$ 1,061,460	$ 175,800
50	Total Firm Sales Variable Costs	$ 1,433,406	$ 831,705	$ 624,469	$ 795,708	$ 977,926	$ 1,672,349	$ 31,128,926	$ 6,335,563

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Attachment NUI-FXW-6, page 2
3	Total Storage	Attachment NUI-FXW-6, page 2
4	Total Peaking	Attachment NUI-FXW-6, page 2
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Attachment NUI-FXW-6, page 2
7	Less Interruptible - New Hampshire	Attachment NUI-FXW-6, page 2
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Attachment NUI-FXW-6, page 1
12	NYMEX Price Used for Forecast	Attachment NUI-FXW-7A
13	NYMEX Price Used for Update	Attachment NUI-FXW-7A
14	Increase/(Decrease) NYMEX Price	LN 13 - LN 12
15	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 14
16	Total Updated Pipeline Costs	LN 15 + LN 11
17		
18	Total Pipeline	LN 16
19	Total Storage	Attachment NUI-FXW-6, page 1
20	Total Peaking	Attachment NUI-FXW-6, page 1
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)	
25	NYMEX NG Futures Contracts	Attachment NUI-FXW-9
26	Average Purchase Price	Attachment NUI-FXW-9
27	NYMEX Price Used for Forecast	Attachment NUI-FXW-7A
28	NYMEX Price Used for Update	Company Analysis
29	Increase/(Decrease) NYMEX Price	LN 28 - LN 27
30	Futures Hedging (Gain)/Loss - Allocate	(LN 26 - LN 27 - LN 29) * LN 25*10,000
31	Price Triggered NYMEX Contracts (NH Only)	
32	NYMEX NG Futures Contracts	Attachment NUI-FXW-9
33	Average Purchase Price	Attachment NUI-FXW-9
34	NYMEX Price Used for Forecast	Attachment NUI-FXW-9
35	NYMEX Price Used for Update	Company Analysis
36	Increase/(Decrease) NYMEX Price	LN 35 - LN 34
37	Futures Hedging (Gain)/Loss (NH ONLY)	(LN 33 - LN 34 - LN 36) * LN 32*10,000
38		
39	Interruptible Cost Estimate	
40	Variable Pipeline Costs Excld Hedges	LN 16
41	Average Supply Cost ($/MMBtu)	LN 40 / LN 2
42	Interruptible Cost - Maine	LN 41 * LN 6
43	Interruptible Cost - New Hampshire	LN 41 * LN 7
44		
45	Firm Sales Pipeline Commodity Excld Hedge	LN 40 - LN 42 - LN 43
46	Total Storage	LN 19
47	Total Peaking	LN 20
48	Firm Sales Variable Costs Excld Hedge	Sum LN 45 : LN 47
49	Plus Hedging (Gain)/Loss	LN 30
50	Total Firm Sales Variable Costs	LN 48 + LN 49

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	SUMMER
Maine	139,433	84,274	57,127	81,672	102,503	169,424	3,157,582	634,433
New Hampshire	166,206	105,914	83,503	96,012	115,113	181,820	3,581,400	748,568
Total	305,639	190,188	140,630	177,684	217,616	351,244	6,738,982	1,383,001
Percentage of Total								
Maine	45.62%	44.31%	40.62%	45.96%	47.10%	48.24%	46.86%	45.87%
New Hampshire	54.38%	55.69%	59.38%	54.04%	52.90%	51.76%	53.14%	54.13%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Commodity Allocation by Jurisdiction

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	SUMMER
Maine								
Firm Sales Pipeline Commodity Excld Hedge	$ 602,006	$ 365,359	$ 250,553	$ 362,102	$ 456,922	$ 769,305	$ 7,818,081	$ 2,806,247
Hedging (Gains) Losses	$ 48,668	$ -	$ -	$ -	$ -	$ 33,340	$ 501,586	$ 82,008
Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,114,409	$ -
Peaking	$ 3,248	$ 3,177	$ 3,120	$ 3,643	$ 3,708	$ 4,019	$ 1,156,889	$ 20,916
Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Maine Commodity Costs	$ 653,922	$ 368,536	$ 253,673	$ 365,745	$ 460,629	$ 806,665	$ 14,590,966	$ 2,909,170
Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,980	$ -
Total Maine Variable Costs	$ 653,922	$ 368,536	$ 253,673	$ 365,745	$ 460,629	$ 806,665	$ 14,599,946	$ 2,909,170
New Hampshire								
Firm Sales Pipeline Commodity Excld Hedge	$ 717,600	$ 459,176	$ 366,235	$ 425,680	$ 513,132	$ 825,592	$ 8,895,889	$ 3,307,415
Hedging (Gains) Losses	$ 58,012	$ -	$ -	$ -	$ -	$ 35,780	$ 1,214,494	$ 93,792
Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,781,213	$ -
Peaking	$ 3,872	$ 3,993	$ 4,561	$ 4,282	$ 4,164	$ 4,314	$ 1,300,984	$ 25,185
New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 779,484	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 865,685	$ 17,192,580	$ 3,426,393
New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,313	$ -
Total New Hampshire Variable Costs	$ 779,484	$ 463,169	$ 370,796	$ 429,963	$ 517,296	$ 865,685	$ 17,202,892	$ 3,426,393
Northern Utilities								
Firm Sales Pipeline Commodity Excld Hedge	$ 1,319,606	$ 824,535	$ 616,788	$ 787,783	$ 970,054	$ 1,594,896	$ 16,713,970	$ 6,113,662
Hedging (Gains) Losses	$ 106,680	$ -	$ -	$ -	$ -	$ 69,120	$ 1,716,080	$ 175,800
Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,895,622	$ -
Peaking	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 2,457,873	$ 46,101
Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Northern Commodity Costs	$ 1,433,406	$ 831,705	$ 624,469	$ 795,708	$ 977,926	$ 1,672,349	$ 31,783,546	$ 6,335,563
Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,293	$ -
Total Northern Variable Costs	$ 1,433,406	$ 831,705	$ 624,469	$ 795,708	$ 977,926	$ 1,672,349	$ 31,802,839	$ 6,335,563

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51	**Commodity Allocation Factors**	
52	Firm Sales Sendout for Normal Winter, MMBtu	
53		
54	Maine	ME Attachment NUI-JDS-4, LN 33 / 10
55	New Hampshire	Company Analysis
56	Total	LN 54 + LN 55
57		
58	**Percentage of Total**	
59	Maine	LN 54 / LN 56
60	New Hampshire	LN 55 / LN 56
61	Total	LN 59 + LN 60
62		
63	**Commodity Allocation by Jurisdiction**	
64	**Maine**	
65	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 59
66	Hedging (Gains) Losses	LN 30 * LN 59
67	Storage	LN 46 * LN 59
68	Peaking	LN 47 * LN 59
69	Maine Interruptible	LN 42
70	Total Maine Commodity Costs	Sum LN 65 : LN 69
71	Maine Inventory Finance Costs	LN 112
72	Total Maine Variable Costs	LN 70 + LN 71
73	**New Hampshire**	
74	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 60
75	Hedging (Gains) Losses	LN 30 * LN 60 + LN 37
76	Storage	LN 46 * LN 60
77	Peaking	LN 47 * LN 60
78	New Hampshire Interruptible	LN 43
79	Total New Hampshire Commodity Costs	Sum LN 74 : LN 78
80	New Hampshire Inventory Finance Costs	LN 117
81	Total New Hampshire Variable Costs	LN 79 + LN 80
82	**Northern Utilities**	
83	Firm Sales Pipeline Commodity Excld Hedge	LN 65 + LN 74
84	Hedging (Gains) Losses	LN 66 + LN 75
85	Storage	LN 67 + LN 76
86	Peaking	LN 68 + LN 77
87	Northern Interruptible	LN 69 + LN 78
88	Total Northern Commodity Costs	LN 70 + LN 79
89	Northern Inventory Finance Costs	LN 71 + LN 80
90	Total Northern Variable Costs	LN 88 + LN 89
91		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

92 **Northern Utilities**
93 **Simplified Market Based Allocator (MBA) Calculations**
94 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**

Line	Col A	Col H	Col I	Col J	Col K	Col L	Col M	Col N	Col P
98	**Inventory Finance Charge**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**TOTAL**	**SUMMER**
99	Storage	$ 256	$ 762	$ 1,272	$ 1,739	$ 1,946	$ 1,946	$ 17,932	$ 7,921
100	Peaking	$ 91	$ 102	$ 105	$ 109	$ 112	$ 115	$ 1,361	$ 634
101	Total	$ 347	$ 864	$ 1,377	$ 1,848	$ 2,058	$ 2,061	$ 19,293	$ 8,555
102									
103	**Inventory Finance Charge Allocation by Jurisdiction**								
104	Maine	$ 158	$ 383	$ 559	$ 849	$ 969	$ 994	$ 8,980	$ 3,913
105	New Hampshire	$ 189	$ 481	$ 818	$ 999	$ 1,089	$ 1,067	$ 10,313	$ 4,642
106	Total	$ 347	$ 864	$ 1,377	$ 1,848	$ 2,058	$ 2,061	$ 19,293	$ 8,555
107									
108	**Inventory Finance Charge Allocation by Month**								
109	**Maine**								
110	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,117,945	0
111	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
112	ME Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,980	$ -
113									
114	**New Hampshire**								
115	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,315,531	0
116	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
117	NH Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,313	$ -

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

LN		
92	**Northern Utilities**	
93	**Simplified Market Based Allocator (MBA) Calculations**	
94	**ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**	
95		
96		
97		
98	**Inventory Finance Charge**	
99	Storage	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
100	Peaking	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
101	Total	Sum LN 99 : LN 100
102		
103	**Inventory Finance Charge Allocation by Jurisdiction**	
104	Maine	LN 101 * LN 59
105	New Hampshire	LN 101 * LN 60
106	Total	Sum LN 104 : LN 105
107		
108	**Inventory Finance Charge Allocation by Month**	
109	**Maine**	
110	Firm Sales Remaining Sendout	ME Attachment NUI-JDS-4, LN 80 / 10
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 Col N
112	ME Allocated Inventory Finance Charge	LN 104 Col N * LN 111
113		
114	**New Hampshire**	
115	Firm Sales Remaining Sendout	Company Analysis
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Schedule 23

Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Supporting Detail to Proposed Tariff Sheets
Average Cost of Gas Calculation

		Winter	Summer	Total	
1	Demand	$ 13,503,746	$ 1,063,217	$ 14,566,963	Schedule 1A, LN 80
2	Commodity	$ 13,776,500	$ 3,426,393	$ 17,202,892	Schedule 1B, LN 0
3	Total	$ 27,280,246	$ 4,489,610	$ 31,769,855	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,028,950	7,400,642	35,429,591	Schedule 10B, LN 11 * 10
6	Forecasted Residential Sales (Therms)	13,035,240	3,274,690	16,309,931	Schedule 10B, LN 3 * 10
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.4818	$0.1437		LN 1 / LN 5
9	Average Commodity Rate	$0.4915	$0.4630		LN 2 / LN 5
10	Average Rate	$0.9733	$0.6067		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 6,404,988	$ 502,104	$ 6,907,092	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 6,280,099	$ 470,573	$ 6,750,672	LN 8 * LN 6
15	**Demand Reallocation:**	$ 124,889	$ 31,531	$ 156,420	LN 13 - LN 14
16	**HLF Allocation**	$ 12,353	$ 7,901	$ 20,254	LN 15 / LN 20
17	**LLF Allocation**	$ 112,536	$ 23,631	$ 136,166	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	9.89%	25.06%		Schedule 10A, LN 173
21	LLF	90.11%	74.94%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 6,408,578	$ 1,515,125	$ 7,923,703	Schedule 10A, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 6,406,947	$ 1,516,182	$ 7,923,128	LN 18 * LN 16
25	**Commodity Reallocation:**	$ 1,632	$ (1,057)	$ 575	LN 23 - LN 24
26	**HLF Allocation**	$ 291	$ (467)	$ (176)	LN 25 / LN 30
27	**LLF Allocation**	$ 1,341	$ (590)	$ 751	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	17.82%	44.17%		Schedule 10C, LN 143
31	LLF	82.18%	55.83%		Schedule 10C, LN 144