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

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2011 - April 30, 2012

	Column A	Column B	Column C
1	**ANTICIPATED DIRECT COST OF GAS**		
2	**Purchased Gas for Sales Service:**		
3	Demand Costs:	$ 2,738,878	
4	Supply Costs:	$ 7,934,188	
5			
6	**Storage & Peaking Gas for Sales Service:**		
7	Demand, Capacity:	$ 14,137,610	
8	Commodity Costs:	$ 6,076,270	
9			
10	**Hedging (Gain)/Loss**	$ 506,830	
11			
12	**Interruptible Sendout Cost**	$ -	
13			
14	**Inventory Finance Charge**	$ 7,294	
15			
16	**Capacity Release**	$ (1,612,415)	
17			
18	**Adjustment for Actual Costs**	$ -	
19			
20	**Total Anticipated Direct Cost of Gas**		$ 29,788,654
21			
22	**ANTICIPATED INDIRECT COST OF GAS**		
23	**Adjustments:**		
24	Prior Period Under/(Over) Collection	$ 973,628	
25	Interest	$ 73,830	
26	Refunds	$ -	
27	Interruptible Margins	$ -	
28	Total Adjustments		$ 1,047,458
29			
30	**Working Capital:**		
31	Total Anticipated Direct Cost of Gas	$ 29,788,654	
32	Working Capital Percentage	0.082%	
33	Working Capital Allowance	$ 24,546	
34			
35	Plus: Working Capital Reconciliation (Acct 182.11)	$ (35,228)	
36			
37	Total Working Capital Allowance		$ (10,682)
38			
39	**Bad Debt:**		
40			
41	Projected Bad Debt	$ 650,000	
42	Bad Debt Supply Portion (47%)	$ 416,526	
43	Seasonal Bad Debt Portion (91%)	$ 377,457	
44	Plus: Bad Debt Reconciliation (Acct 182.16)	$ 1,935	
45	Total Bad Debt Allowance		$ 379,392
46			
47	**Local Production and Storage Capacity**		$ 349,700
48			
49	**Miscellaneous Overhead-79.31% Allocated to Winter Season**		$ 349,601
50			
51	**Total Anticipated Indirect Cost of Gas**		$ 2,115,470
52			
53	**Total Cost of Gas**		$ 31,904,124
54			

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

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2011 - April 30, 2012

	Column A	Reference **Column D**
1	**ANTICIPATED DIRECT COST OF GAS**	
2	**Purchased Gas for Sales Service:**	
3	Demand Costs:	Schedule 1A, LN 71
4	Supply Costs:	Schedule 1B, LN 14
5		
6	**Storage & Peaking Gas for Sales Service:**	
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 Sendout Cost**	-(Schedule 1B, LN 22)
13		
14	**Inventory Finance Charge**	Schedule 22, LN 105
15		
16	**Capacity Release**	-(Schedule 1A, LN 76)
17		
18	**Adjustment for Actual Costs**	
19		
20	**Total Anticipated Direct Cost of Gas**	Sum (LN 3 : LN 18)
21		
22	**ANTICIPATED INDIRECT COST OF GAS**	
23	**Adjustments:**	
24	Prior Period Under/(Over) Collection	Schedule 3, LN 103: April 2010
25	Interest	Schedule 3, LN 111
26	Refunds	Company Analysis
27	Interruptible Margins	-(Schedule 1A, LN 77)
28	Total Adjustments	Sum (LN 24 : LN 27)
29		
30	**Working Capital:**	
31	Total Anticipated Direct Cost of Gas	LN 20
32	Working Capital Percentage	NHPUC No. 10 Section 4.06.1
33	Working Capital Allowance	LN 31 * LN 32
34		
35	Plus: Working Capital Reconciliation (Acct 182.11)	Company Analysis
36		
37	Total Working Capital Allowance	Sum (LN 33 : LN 35)
38		
39	**Bad Debt:**	
40		
41	Projected Bad Debt	Schedule 3B LN 15
42	Bad Debt Supply Portion (47%)	Schedule 3B LN 16
43	Seasonal Bad Debt Portion (91%)	Schedule 3B LN 17
44	Plus: Bad Debt Reconciliation (Acct 182.16)	Schedule 15, Attachment B
45	Total Bad Debt Allowance	LN 43 + LN 44
46		
47	**Local Production and Storage Capacity**	Schedule 1A, LN 84
48		
49	**Miscellaneous Overhead-79.31% Allocated to Winter Seasor**	Schedule 1A, LN 83
50		
51	**Total Anticipated Indirect Cost of Gas**	Sum (LN 28 : LN 49)
52		
53	**Total Cost of Gas**	LN 51 + LN 20
54		

			Column B		Column C	
57	CALCULATION OF FIRM SALES COST OF GAS RATE					
58	Period Covered: November 1, 2011 - April 30, 2012					
60	**Column A**		**Column B**		**Column C**	
62	Total Anticipated Direct Cost of Gas		$ 29,788,654			
63	Projected Prorated Sales (11/01/11 - 04/30/12)		28,614,458			
64	**Direct Cost of Gas Rate**			$	1.0410	per therm
66	**Demand Cost of Gas Rate**		$ 15,264,073	$	0.5334	per therm
67	**Commodity Cost of Gas Rate**		$ 14,524,582	$	0.5076	per therm
68	**Total Direct Cost of Gas Rate**		$ 29,788,654	$	1.0410	per therm
70	Total Anticipated Indirect Cost of Gas		$ 2,115,470			
71	Projected Prorated Sales (11/01/11 - 04/30/12)		28,614,458			
72	**Indirect Cost of Gas**			$	0.0739	per therm
75	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/05**			**$**	**1.1149**	**per therm**
77	**RESIDENTIAL COST OF GAS RATE - 11/01/11**		**COGwr**	**$**	**1.1149**	**per therm**
78		Maximum (COG+25%)		**$**	**1.3936**	
81	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/11**		**COGwl**	**$**	**0.9542**	**per therm**
82		Maximum (COG+25%)		**$**	**1.1928**	
84	C&I HLF Demand Costs Allocated per SMBA	$ 839,472				
85	PLUS: Residential Demand Reallocation to C&I HLF	$ 46,426				
86	C&I HLF Total Adjusted Demand Costs	$ 885,898				
87	C&I HLF Projected Prorated Sales (11/01/11 - 04/30/12)	2,555,355				
88	**Demand Cost of Gas Rate**	**$ 0.3467**				
90	C&I HLF Commodity Costs Allocated per SMBA	$ 1,364,598				
91	PLUS: Residential Commodity Reallocation to C&I HLF	$ (1,018)				
92	C&I HLF Total Adjusted Commodity Costs	$ 1,363,580				
93	C&I HLF Projected Prorated Sales (11/01/11 - 04/30/12)	2,555,355				
94	**Commodity Cost of Gas Rate**	**$ 0.5336**				
96	**Indirect Cost of Gas**	**$ 0.0739**				
98	**Total C&I HLF Cost of Gas Rate**	**$ 0.9542**				
101	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/11**		**COGwh**	**$**	**1.1477**	**per therm**
102		Maximum (COG+25%)		**$**	**1.4346**	
104	C&I LLF Demand Costs Allocated per SMBA	$ 6,784,383				
105	PLUS: Residential Demand Reallocation to C&I LLF	$ 375,201				
106	C&I LLF Total Adjusted Demand Costs	$ 7,159,583				
107	C&I LLF Projected Prorated Sales (11/01/11 - 04/30/12)	12,526,929				
108	**Demand Cost of Gas Rate**	**$ 0.5715**				
110	C&I LLF Commodity Costs Allocated per SMBA	$ 6,296,823				
111	PLUS: Residential Commodity Reallocation to C&I LLF	$ (4,698)				
112	C&I LLF Total Adjusted Commodity Costs	$ 6,292,125				
113	C&I LLF Projected Prorated Sales (11/01/11 - 04/30/12)	12,526,929				
114	**Commodity Cost of Gas Rate**	**$ 0.5023**				
116	**Indirect Cost of Gas**	**$ 0.0739**				
118	**Total C&I LLF Cost of Gas Rate**	**$ 1.1477**				

55		
56		
57	CALCULATION OF FIRM SALES COST OF GAS RATE	
58	Period Covered: November 1, 2011 - April 30, 2012	
59		
60	**Column A**	**Column D**
61		
62	Total Anticipated Direct Cost of Gas	LN 20
63	Projected Prorated Sales (11/01/11 - 04/30/12)	Schedule 10B LN 16
64	**Direct Cost of Gas Rate**	LN 62 / LN 63
65		
66	**Demand Cost of Gas Rate**	Column B : SUM (LN 3 , LN 7 , LN 16)
67	**Commodity Cost of Gas Rate**	Column B : SUM (LN 4 , LN 8 , LN 10 , LN 12 , LN 14)
68	**Total Direct Cost of Gas Rate**	SUM (LN 66 : LN 67)
69		
70	Total Anticipated Indirect Cost of Gas	LN 51
71	Projected Prorated Sales (11/01/11 - 04/30/12)	Schedule 10B LN 16
72	**Indirect Cost of Gas**	LN 70 / LN 71
73		
74		
75	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/05**	LN 68 + LN 72
76		
77	**RESIDENTIAL COST OF GAS RATE - 11/01/11**	Company Analysis
78		LN 77 * 1.25
79		
80		
81	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/11**	Company Analysis
82		LN 81 * 1.25
83		
84	C&I HLF Demand Costs Allocated per SMBA	Schedule 10A, LN 169
85	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 23, LN 24
86	C&I HLF Total Adjusted Demand Costs	Sum (LN 84 : LN 85)
87	C&I HLF Projected Prorated Sales (11/01/11 - 04/30/12)	Schedule 10B LN 14
88	**Demand Cost of Gas Rate**	LN 86 / LN 87
89		
90	C&I HLF Commodity Costs Allocated per SMBA	Schedule 10C, LN 139
91	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 23, LN 26
92	C&I HLF Total Adjusted Commodity Costs	Sum (LN 90 : LN 91)
93	C&I HLF Projected Prorated Sales (11/01/11 - 04/30/12)	Schedule 10B LN 14
94	**Commodity Cost of Gas Rate**	LN 92 / LN 93
95		
96	**Indirect Cost of Gas**	LN 72
97		
98	**Total C&I HLF Cost of Gas Rate**	Sum (LN 88, LN 94, LN 96)
99		
100		
101	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/11**	Company Analysis
102		LN 101 * 1.25
103		
104	C&I LLF Demand Costs Allocated per SMBA	Schedule 10A, LN 170
105	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 23, LN 17
106	C&I LLF Total Adjusted Demand Costs	Sum (LN 104 : LN 105)
107	C&I LLF Projected Prorated Sales (11/01/11 - 04/30/12)	Schedule 10B LN 15
108	**Demand Cost of Gas Rate**	LN 106 / LN 107
109		
110	C&I LLF Commodity Costs Allocated per SMBA	Schedule 10C, LN 140
111	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 23, LN 27
112	C&I LLF Total Adjusted Commodity Costs	Sum (LN 110 : LN 111)
113	C&I LLF Projected Prorated Sales (11/01/11 - 04/30/12)	Schedule 10B LN 15
114	**Commodity Cost of Gas Rate**	LN 112 / LN 113
115		
116	**Indirect Cost of Gas**	LN 72
117		
118	**Total C&I LLF Cost of Gas Rate**	Sum (LN 108, LN 114, LN 116)

Schedule 1A and 1B

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	$ 4,044,355
3	Storage	$ 16,867,369
4	Peaking	$ 866,963
5	Total Gross Demand Cost	$ 21,778,687
6		
7	Capacity Assignment Demand Revenue Estimate	$ 3,924,022
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 21,778,687
9	Capacity Assignment as % of Total Gross Demand Cost	18.02%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 728,700
14	Storage	$ 3,039,115
15	Peaking	$ 156,207
16	Total Capacity Assignment Credit	$ 3,924,022
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 3,315,655
21	Storage	$ 13,828,255
22	Peaking	$ 710,756
23	Total Net Demand Cost (Less Capacity Assignment)	$ 17,854,665
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	13,681
28	Less 18.02% NH Transp. Capacity Assignment	(2,465)
29	Net Pipeline MDQ	11,216
30		
31	Net Pipeline MDQ	11,216
32	Less: Firm Sales Base Use	3,475
33	Remaining Pipeline MDQ	7,741
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$295.62
37		
38		**Costs**
39	Pipeline & Product Demand	$ 3,315,655
40	Less: Base Pipeline Use	$ 1,027,191
41	Remaining Pipeline Use	$ 2,288,464

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	Schedule 5B page 1
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 DEMAND COSTS**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 18.02% 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

Line		Nov	Dec	Jan	Feb	Mar	Apr	Winter
42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**							
43	(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)							
44								
45	**All Months**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
46	Remaining Load for All Months	2,653,282	4,376,435	5,155,015	4,458,499	3,771,225	2,147,722	22,562,178
47	Rank	5	3	1	2	4	6	
48	% Max Month	51.47%	84.90%	100.00%	86.49%	73.16%	41.66%	
49	PR	1.96%	3.91%	13.51%	0.80%	5.42%	4.75%	
50	CumPR	8.45%	17.78%	32.09%	18.58%	13.87%	6.48%	97.24%
51								
52	**Peak Months Only**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
53	Remaining Load for Peak Months Only	2,653,282	4,376,435	5,155,015	4,458,499	3,771,225	2,147,722	
54	Rank	5	3	1	2	4	6	
55	% Max Month	51.47%	84.90%	100.00%	86.49%	73.16%	41.66%	
56	PR	1.96%	3.91%	13.51%	0.80%	5.42%	6.94%	
57	CumPR	8.91%	18.24%	32.55%	19.04%	14.33%	6.94%	100.00%
58								
59	**DEMAND COST PR ALLOCATORS**							
60		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	50.00%
62	Pipeline - Remaining	8.45%	17.78%	32.09%	18.58%	13.87%	6.48%	97.24%
63	Storage & Peaking	8.45%	17.78%	32.09%	18.58%	13.87%	6.48%	97.24%
64	Capacity Release	8.91%	18.24%	32.55%	19.04%	14.33%	6.94%	100.00%
65	Interr. Margins & Off Sys Sales	8.91%	18.24%	32.55%	19.04%	14.33%	6.94%	100.00%
66								
67	**DEMAND COSTS ALLOCATED TO MONTHS**							
68		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
69	Pipeline - Base	$ 85,599	$ 85,599	$ 85,599	$ 85,599	$ 85,599	$ 85,599	$ 513,596
70	Pipeline - Remaining	$ 193,263	$ 406,892	$ 734,311	$ 425,107	$ 317,335	$ 148,376	$ 2,225,283
71	Total Pipeline	$ 278,862	$ 492,491	$ 819,910	$ 510,706	$ 402,934	$ 233,975	$ 2,738,878
72								
73	Storage & Peaking	$ 1,227,831	$ 2,585,053	$ 4,665,206	$ 2,700,778	$ 2,016,083	$ 942,659	$ 14,137,610
74								
75	Less Credits to Demand Cost							
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 143,589	$ 294,109	$ 524,803	$ 306,943	$ 231,008	$ 111,963	$ 1,612,415
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79								
80	Total Direct Demand Costs	$ 1,363,104	$ 2,783,435	$ 4,960,313	$ 2,904,541	$ 2,188,008	$ 1,064,671	$ 15,264,073
81								
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

NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR /ALLOCATORS)
(Based on NH Firm Sales Sendout for Remaining Temperature Sensitnsitive Load)

All Months	**Total**	**Winter**	**Summer**
Remaining Load for All Months	23,718,727	22,562,178	1,156,549
Rank			
% Max Month			
PR	32.09%		
CumPR	100.00%	97.24%	2.76%

Peak Months Only	**Total**	**Winter**	**Summer**
Remaining Load for Peak Months Only	22,562,178		
Rank			
% Max Month			
PR	32.55%		
CumPR	100.00%	100.00%	0.00%

DEMAND COST PR ALLOCATORS

	Total	**Winter**	**Summer**
Pipeline - Base	100.00%	50.00%	50.00%
Pipeline - Remaining	100.00%	97.24%	2.76%
Storage & Peaking	100.00%	97.24%	2.76%
Capacity Release	100.00%	100.00%	0.00%
Interr. Margins & Off Sys Sales	100.00%	100.00%	0.00%

DEMAND COSTS ALLOCATED TO MONTHS

	Total	**Winter**	**Summer**	**Winter**	**Summer**
Pipeline - Base	$ 1,027,191	$ 513,596	$ 513,596	50.00%	50.00%
Pipeline - Remaining	$ 2,288,464	$ 2,225,283	$ 63,181	97.24%	2.76%
Total Pipeline	$ 3,315,655	$ 2,738,878	$ 576,777	82.60%	17.40%
Storage & Peaking	$ 14,539,011	$ 14,137,610	$ 401,401	97.24%	2.76%
Less Credits to Demand Cost					
Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$1,612,415	$ 1,612,415	$ -	100.00%	0.00%
Interruptible Margins	$ -	$ -	$ -		
Re-Entry Fee Credits	$ -	$ -	$ -		
Total Direct Demand Costs	$ 16,242,250	$ 15,264,073	$ 978,177	93.98%	6.02%
Indirect Demand Costs/(Credits)					
Miscellaneous Overhead	$ 440,825	$ 349,601	$ 91,224	79.31%	20.69%
Local Production & Storage	$ 349,700	$ 349,700	$ -	100.00%	0.00%
Subtotal	$ 790,525	$ 699,301	$ 91,224	88.46%	11.54%

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

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

New Hampshire PNGTS Refund, Litigation Costs and Asset Management & Capacity Release Revenue

		Total	Capacity Assigned	Sales
1	Asset Management	($1,917,918)	($71,945)	($1,845,973)
2	PNGTS Litigation	$414,873	$34,007	$380,866
3	PNGTS Refund	$0	$0	$0
4	PNGTS litigation net of Refund	$414,873	$34,007	$380,866
5	Asset Management plus PNGTS			($1,465,107)
6	Capacity Release Revenues			($147,308)
7	Total NH Cap Rel and Asset Management			($1,612,415)

Notes
1 Capacity Assigned values from Schedule 5B page 1
2 Total PNGTS Litigation and Refund values from Schedule 5B page 6
3 Total Asset Management revenues from Schedule 25, line 9 x line 89

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	TOTAL	WINTER
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	3,244,399	3,003,121	1,887,443	1,461,667	2,756,309	3,173,869	51,279,909	15,526,809
2	New Hampshire Sales Storage	444,189	2,443,085	4,326,572	3,997,577	2,084,745	0	13,296,167	13,296,167
3	New Hampshire Sales Peaking	7,090	7,371	18,144	6,907	7,315	16,251	106,440	63,078
4	Total New Hampshire Firm Sales Sendout	3,695,679	5,453,577	6,232,158	5,466,150	4,848,369	3,190,120	64,682,516	28,886,054
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	3,695,679	5,453,577	6,232,158	5,466,150	4,848,369	3,190,120	64,682,516	28,886,054
9	Total Firm Sales	3,660,851	5,402,430	6,173,777	5,414,848	4,802,750	3,159,801	36,081,030	28,614,458
10	Difference (LAUF & Company Use)	34,828	51,147	58,381	51,302	45,619	30,319	28,601,486	271,596
11	Percent Difference	0.94%	0.94%	0.94%	0.94%	0.94%	0.95%	44.22%	0.94%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 1,572,943	$ 1,535,110	$ 1,057,012	$ 847,137	$ 1,450,318	$ 1,471,667	$ 11,509,498	$ 7,934,188
15	New Hampshire Hedging (Gains) Losses	$ 46,208	$ 94,670	$ 116,228	$ 119,724	$ 94,055	$ 35,945	$ 523,383	$ 506,830
16	New Hampshire Total Storage	$ 201,390	$ 1,107,981	$ 1,963,268	$ 1,814,009	$ 946,838	$ -	$ 6,033,487	$ 6,033,487
17	New Hampshire Total Peaking	$ 4,580	$ 4,816	$ 12,601	$ 4,926	$ 5,129	$ 10,730	$ 70,206	$ 42,782
18	New Hampshire Inventory Finance Charge	$ 858	$ 1,415	$ 1,667	$ 1,441	$ 1,219	$ 694	$ 7,294	$ 7,294
19	Total New Hampshire Sales Variable Costs	$ 1,825,980	$ 2,743,992	$ 3,150,777	$ 2,787,238	$ 2,497,559	$ 1,519,036	$ 18,143,868	$ 14,524,582
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,779,772	$ 2,649,322	$ 3,034,548	$ 2,667,514	$ 2,403,504	$ 1,483,091	$ 17,620,485	$ 14,017,752
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 1,825,980	$ 2,743,992	$ 3,150,777	$ 2,787,238	$ 2,497,559	$ 1,519,036	$ 18,143,868	$ 14,524,582
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	0.4848	0.5112	0.5600	0.5796	0.5262	0.4637	$ 0.2244	$ 0.5110
27	New Hampshire Hedging (Gains) Losses	0.0142	0.0315	0.0616	0.0819	0.0341	0.0113	$ 0.0102	$ 0.0326
28	New Hampshire Storage Excld Inventory Finance Costs	0.4534	0.4535	0.4538	0.4538	0.4542	0.0000	$ 0.4538	$ 0.4538
29	New Hampshire Peaking Excld Inventory Finance Costs	0.6460	0.6533	0.6945	0.7132	0.7011	0.6603	$ 0.6596	$ 0.6782
30	New Hampshire Inventory Finance Costs per Dth Stor and F	0.0019	0.0006	0.0004	0.0004	0.0006	0.0427	$ 0.0005	$ 0.0005
31	Weighted Average Cost per Dth Sendout	0.4941	0.5032	0.5056	0.5099	0.5151	0.4762	$ 0.2805	$ 0.5028
32									
33	New Hampshire Interruptible Cost / Therm	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	1,042,408	1,077,155	1,077,155	1,007,661	1,077,155	1,042,408	12,708,083	6,323,942
37	Base Commodity Cost Excld Hedging	$ 505,378	$ 550,611	$ 603,232	$ 584,010	$ 566,779	$ 483,346	$ 3,931,770	$ 3,293,356
38	Base Hedging Commodity Cost	$ 14,846	$ 33,956	$ 66,331	$ 82,537	$ 36,756	$ 11,805	$ 248,647	$ 246,232
39	Remaining Commodity Excld Hedging	$ 1,274,393	$ 2,098,711	$ 2,431,316	$ 2,083,504	$ 1,836,726	$ 999,745	$ 13,688,715	$ 10,724,396
40	Remaining Hedging Commodity	$ 31,362	$ 60,714	$ 49,897	$ 37,187	$ 57,299	$ 24,139	$ 274,736	$ 260,598
41	Total Commodity Excld Hedging	$ 1,779,772	$ 2,649,322	$ 3,034,548	$ 2,667,514	$ 2,403,504	$ 1,483,091	$ 17,620,485	$ 14,017,752
42	Total Hedging	$ 46,208	$ 94,670	$ 116,228	$ 119,724	$ 94,055	$ 35,945	$ 523,383	$ 506,830
43	Total Commodity (Incl Hedging)	$ 1,825,980	$ 2,743,992	$ 3,150,777	$ 2,787,238	$ 2,497,559	$ 1,519,036	$ 18,143,868	$ 14,524,582

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
15	New Hampshire Hedging (Gains) Losses	Schedule 22, LN 75
16	New Hampshire Total Storage	Schedule 22, LN 76
17	New Hampshire Total Peaking	Schedule 22, LN 77
18	New Hampshire Inventory Finance Charge	Schedule 22, LN 80
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

Unitil
Northern Utilities, Inc.

Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through April 2012			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Production	$6,764,622	1,495,554	$4.5232
Tenn Zone 4 Spot	$762,777	168,345	$4.5310
Washington 10 Storage	$10,539,039	2,324,515	$4.5339
Tennessee Storage	$910,102	198,563	$4.5835
Chicago	$878,328	188,922	$4.6491
Niagara	$55,157	11,194	$4.9274
PNGTS	$1,082,241	181,363	$5.9673
Lewiston Baseload	$5,560,110	911,000	$6.1033
LNG	$81,501	12,018	$6.7818
Total System	$26,633,877	5,491,472	$4.8500

Schedule 3A and 3B

Northern Utilities, Inc.

Peak Period

Northern Utilities

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

			Summer						Winter						
	Sales Revenues		(Actual)	(Actual)	(Actual)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1		Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
2	Volumes														
3	Residential Heat & Non Heat								1,731,009	2,555,596	2,920,229	2,560,783	2,271,243	1,493,314	13,532,174
4	Sales HLF Classes								327,421	481,082	550,250	483,511	428,986	284,104	2,555,355
5	Sales LLF Classes								1,602,420	2,365,752	2,703,298	2,370,554	2,102,522	1,382,382	12,526,929
6	Total								3,660,851	5,402,430	6,173,777	5,414,848	4,802,750	3,159,801	28,614,458
7	Rates														
8	Residential Heat & Non Heat CGA								$1.1149	$1.1149	$1.1149	$1.1149	$1.1149	$1.1149	
9	Sales HLF Classes CGA								$0.9542	$0.9542	$0.9542	$0.9542	$0.9542	$0.9542	
10	Sales LLF Classes CGA								$1.1477	$1.1477	$1.1477	$1.1477	$1.1477	$1.1477	
11	Revenues														
12	Residential Heat & Non Heat								$ (1,929,902)	$ (2,849,234)	$ (3,255,763)	$ (2,855,017)	$ (2,532,208)	$ (1,664,896)	$ (15,087,020)
13	Sales HLF Classes								$ (312,426)	$ (459,048)	$ (525,049)	$ (461,366)	$ (409,338)	$ (271,092)	$ (2,438,320)
14	Sales LLF Classes								$ (1,839,098)	$ (2,715,174)	$ (3,102,575)	$ (2,720,685)	$ (2,413,065)	$ (1,586,560)	$ (14,377,156)
15	Total Sales Revenues								$ (4,081,425)	$ (6,023,456)	$ (6,883,387)	$ (6,037,068)	$ (5,354,611)	$ (3,522,549)	$ (31,902,496)
16															
17			Summer						Winter						
18	**Gas Costs and Credits**		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
19			May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
20	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
21	Pipeline		$ 226,895	$ 226,895	$ 226,895	$ 226,895	$ 226,895	$ 226,895	$ 230,123	$ 230,123	$ 230,123	$ 230,123	$ 230,123	$ 226,895	$ 2,738,878
22	Storage		$ 708,812	$ 708,812	$ 708,812	$ 708,812	$ 708,812	$ 708,812	$ 1,692,934	$ 1,692,934	$ 1,692,934	$ 1,692,934	$ 1,692,934	$ 708,812	$ 13,426,355
23	Peaking		$ 41,429	$ 41,429	$ 41,429	$ 41,429	$ 41,429	$ 41,429	$ 80,226	$ 80,226	$ 80,226	$ 80,226	$ 80,226	$ 41,429	$ 691,133
24	Total Demand Costs		$ 977,136	$ 977,136	$ 977,136	$ 977,136	$ 977,136	$ 977,136	$ 2,003,283	$ 2,003,283	$ 2,003,283	$ 2,003,283	$ 2,003,283	$ 977,136	$ 16,856,367
25	NUI Commodity Costs														
26	NUI Total Pipeline Volumes								617,729	568,332	359,160	276,160	525,649	609,348	2,956,378
27	Pipeline Costs Modeled in Sendout™								$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	$ 15,103,235
28	NYMEX Price Used for Forecast								$ 4.0430	$ 4.2590	$ 4.3830	$ 4.3900	$ 4.3590	$ 4.3440	
29	NYMEX Price Used for Update								$ 4.0430	$ 4.2590	$ 4.3830	$ 4.3900	$ 4.3590	$ 4.3440	
30	Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
31	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
32	Updated Pipeline Costs								$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 4.85	$ 5.11	$ 5.60	$ 5.80	$ 5.26	$ 4.64	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	
37	New Hampshire Allocated Percentage								52.52%	52.84%	52.55%	52.93%	52.44%	52.09%	
38	NH Updated Pipeline Costs								$ 1,572,943	$ 1,535,110	$ 1,057,012	$ 847,137	$ 1,450,318	$ 1,471,667	$ 7,934,188
39	Hedging (Gain)/Loss Estimate														
40	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
41	NYMEX NG Futures Contracts								9	16	21	22	17	11	
42	Average Purchase Price								$ 5.0206	$ 5.3788	$ 5.4362	$ 5.4182	$ 5.4141	$ 4.9714	
43	NYMEX Price Used for Forecast								$ 4.0430	$ 4.2590	$ 4.3830	$ 4.3900	$ 4.3590	$ 4.3440	
44	NYMEX Price Used for Update								$ 4.0430	$ 4.2590	$ 4.3830	$ 4.3900	$ 4.3590	$ 4.3440	
45	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ 87,980	$ 179,160	$ 221,170	$ 226,200	$ 179,370	$ 69,010	$ 962,890
47	New Hampshire Allocated Percentage								52.52%	52.84%	52.55%	52.93%	52.44%	52.09%	
48	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 46,208	$ 94,670	$ 116,228	$ 119,724	$ 94,055	$ 35,945	$ 506,830

Peak Period

Northern Utilities

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

			Summer						Winter						
	Sales Revenues		(Actual)	(Actual)	(Actual)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1		Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
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								$ 4.0430	$ 4.2590	$ 4.3830	$ 4.3900	$ 4.3590	$ 4.3440	
53	NYMEX Price Used for Update								$ 4.0430	$ 4.2590	$ 4.3830	$ 4.3900	$ 4.3590	$ 4.3440	
54	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
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								$ 1,572,943	$ 1,535,110	$ 1,057,012	$ 847,137	$ 1,450,318	$ 1,471,667	$ 7,934,188
60	Hedging (Gain)/Loss Estimate								$ 46,208	$ 94,670	$ 116,228	$ 119,724	$ 94,055	$ 35,945	$ 506,830
61	Storage								$ 201,390	$ 1,107,981	$ 1,963,268	$ 1,814,009	$ 946,838	$ -	$ 6,033,487
62	Peaking								$ 4,580	$ 4,816	$ 12,601	$ 4,926	$ 5,129	$ 10,730	$ 42,782
63	Total Commodity Costs								$ 1,825,122	$ 2,742,577	$ 3,149,110	$ 2,785,797	$ 2,496,340	$ 1,518,342	$ 14,517,288
64	Inventory Finance Charge		$ 177	$ 404	$ 644	$ 870	$ 971	$ 960	$ 920	$ 899	$ 729	$ 465	$ 196	$ 59	$ 7,294
65	Asset Management and Capacity Release														
66	NUI AMA Revenue		$ (266,417)	$ (266,417)	$ (266,417)	$ (266,417)	$ (266,417)	$ (266,417)	$ (444,417)	$ (444,417)	$ (444,417)	$ (444,417)	$ (444,417)	$ (266,417)	$ (4,087,000)
67	PNGTS Litigation Cost		$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 31,739	$ 380,866
68	NUI Capacity Release		$ (34,465)	$ (34,465)	$ (45,624)	$ (45,624)	$ (45,624)	$ (24,949)	$ (13,790)	$ (13,790)	$ (13,790)	$ (13,790)	$ (13,790)	$ (13,790)	$ (313,490)
69	NUI AMA Rev & Cap. Release Subtotal		$ (269,143)	$ (269,143)	$ (280,302)	$ (280,302)	$ (280,302)	$ (259,627)	$ (426,468)	$ (426,468)	$ (426,468)	$ (426,468)	$ (426,468)	$ (248,468)	$ (4,019,624)
70	NH AMA Revenue		$ (93,283)	$ (93,283)	$ (93,283)	$ (93,283)	$ (93,283)	$ (93,283)	$ (176,814)	$ (176,814)	$ (176,814)	$ (176,814)	$ (176,814)	$ (93,283)	$ (1,537,052)
71	NH Capacity Release		$ (16,195)	$ (16,195)	$ (21,438)	$ (21,438)	$ (21,438)	$ (11,723)	$ (6,480)	$ (6,480)	$ (6,480)	$ (6,480)	$ (6,480)	$ (6,480)	$ (147,308)
72	NH Total Asset Management and Capacity Release		$ (109,478)	$ (109,478)	$ (114,722)	$ (114,722)	$ (114,722)	$ (105,007)	$ (183,294)	$ (183,294)	$ (183,294)	$ (183,294)	$ (183,294)	$ (99,763)	$ (1,684,360)

Peak Period

Northern Utilities

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

			Summer						Winter						
	Sales Revenues		(Actual)	(Actual)	(Actual)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1		Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
73															
74	**Total Anticipated Direct Cost of Gas**		$ 867,834	$ 868,061	$ 863,058	$ 863,284	$ 863,385	$ 873,089	$ 3,646,032	$ 4,563,466	$ 4,969,829	$ 4,606,251	$ 4,316,525	$ 2,395,774	$ 29,696,588
75			Winter						Summer						
76			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ 867,834	$ 868,061	$ 863,058	$ 863,284	$ 863,385	$ 873,089	$ 3,646,032	$ 4,563,466	$ 4,969,829	$ 4,606,251	$ 4,316,525	$ 2,395,774	$ 29,696,588
80	Working Capital Percentage		0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
81	Working Capital Allowance		$ 715	$ 715	$ 711	$ 711	$ 711	$ 719	$ 3,004	$ 3,760	$ 4,095	$ 3,796	$ 3,557	$ 1,974	$ 24,470
82	Beginning Period Working Capital Balance		$ (35,228)	$ (34,576)	$ (33,923)	$ (33,273)	$ (32,622)	$ (31,969)	$ (31,308)	$ (28,358)	$ (24,646)	$ (20,592)	$ (16,830)	$ (13,301)	
83	End of Period Working Capital Allowance		$ (34,513)	$ (33,861)	$ (33,212)	$ (32,562)	$ (31,911)	$ (31,250)	$ (28,303)	$ (24,597)	$ (20,550)	$ (16,796)	$ (13,273)	$ (11,327)	
84	Interest		$ (64)	$ (62)	$ (61)	$ (60)	$ (59)	$ (58)	$ (54)	$ (48)	$ (41)	$ (34)	$ (27)	$ (22)	$ (591)
85	End of period with Interest	$ (35,228)	$ (34,576)	$ (33,923)	$ (33,273)	$ (32,622)	$ (31,969)	$ (31,308)	$ (28,358)	$ (24,646)	$ (20,592)	$ (16,830)	$ (13,301)	$ (11,349)	
86	Bad Debt														
87	Total Anticipated Direct Cost of Gas		$ -						$ 3,646,032	$ 4,563,466	$ 4,969,829	$ 4,606,251	$ 4,316,525	$ 2,395,774	$ 24,497,876
88	Prior Period Over/Under Collection	$ 1,935	$ -	$ -	$ -	$ -	$ -	$ -							$ 1,935
89	Bad Debt Allowance		$ -						$ 56,177	$ 70,313	$ 76,574	$ 70,972	$ 66,508	$ 36,914	$ 377,457
90	Beginning Period Bad Debt Balance		$ 1,935	$ 1,939	$ 1,942	$ 1,946	$ 1,949	$ 1,953	$ 1,956	$ 58,188	$ 128,671	$ 205,549	$ 276,960	$ 344,034	
91	End of Period Bad Debt Balance		$ 1,935	$ 1,939	$ 1,942	$ 1,946	$ 1,949	$ 1,953	$ 58,133	$ 128,501	$ 205,245	$ 276,521	$ 343,468	$ 380,947	
92	Interest		$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 55	$ 170	$ 304	$ 439	$ 565	$ 660	$ 2,215
93	End of Period Bad Debt Balance with Interest	$ 1,935	$ 1,939	$ 1,942	$ 1,946	$ 1,949	$ 1,953	$ 1,956	$ 58,188	$ 128,671	$ 205,549	$ 276,960	$ 344,034	$ 381,607	
94	Local Production and Storage Capacity								$ 58,283	$ 58,283	$ 58,283	$ 58,283	$ 58,283	$ 58,283	$ 349,700
95	Miscellaneous Overhead								$ 58,267	$ 58,267	$ 58,267	$ 58,267	$ 58,267	$ 58,267	$ 349,601
96	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
97	Beginning Balance Over/Under Collection		$ 973,628	$ 1,844,027	$ 2,716,238	$ 3,585,031	$ 4,455,633	$ 5,327,922	$ 6,211,514	$ 5,903,698	$ 4,569,789	$ 2,779,470	$ 1,469,069	$ 549,371	
98	Net Costs - Revenues		$ 867,834	$ 868,061	$ 863,058	$ 863,284	$ 863,385	$ 873,089	$ (318,843)	$ (1,343,440)	$ (1,797,008)	$ (1,314,267)	$ (921,535)	$ (1,010,225)	
99	Ending Balance before Interest		$ 1,841,462	$ 2,712,088	$ 3,579,296	$ 4,448,315	$ 5,319,018	$ 6,201,012	$ 5,892,671	$ 4,560,257	$ 2,772,781	$ 1,465,203	$ 547,534	$ (460,854)	
100	Average Balance		$ 1,407,545	$ 2,278,057	$ 3,147,767	$ 4,016,673	$ 4,887,325	$ 5,764,467	$ 6,052,093	$ 5,231,977	$ 3,671,285	$ 2,122,336	$ 1,008,302	$ 44,259	
101	Interest Rate		2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
102	Interest Expense		$ 2,564	$ 4,150	$ 5,735	$ 7,318	$ 8,904	$ 10,502	$ 11,026	$ 9,532	$ 6,689	$ 3,867	$ 1,837	$ 81	$ 72,206
103	Ending Balance Incl Interest Expense	$ 973,628	$ 1,844,027	$ 2,716,238	$ 3,585,031	$ 4,455,633	$ 5,327,922	$ 6,211,514	$ 5,903,698	$ 4,569,789	$ 2,779,470	$ 1,469,069	$ 549,371	$ (460,773)	
104	**Total Over/Under Collection Ending Balance**		$ 1,811,389	$ 2,684,257	$ 3,553,703	$ 4,424,960	$ 5,297,906	$ 6,182,163	$ 5,933,528	$ 4,673,815	$ 2,964,428	$ 1,729,200	$ 880,104	$ (90,515)	
105															$ -
106															
107	**Total Indirect Cost of Gas**	$ 940,335	$ 3,220	$ 4,807	$ 6,389	$ 7,973	$ 9,560	$ 11,168	$ 186,759	$ 200,277	$ 204,171	$ 195,590	$ 188,990	$ 156,156	$ 2,115,394
108															
109	**Total Cost of Gas**	$ 940,335	$ 871,054	$ 872,868	$ 869,446	$ 871,257	$ 872,946	$ 884,257	$ 3,832,791	$ 4,763,743	$ 5,174,000	$ 4,801,841	$ 4,505,515	$ 2,551,930	$ 31,811,982
110															
111	**Total Interest**	$ -	$ 2,504	$ 4,092	$ 5,677	$ 7,262	$ 8,849	$ 10,448	$ 11,027	$ 9,654	$ 6,952	$ 4,272	$ 2,375	$ 719	$ 73,830

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2011**			
2				
3	Total	$	597,172	Company Analysis
4	Distribution	$	214,499	Company Analysis
5	Non-Distribution	$	382,673	Company Analysis
6	Non-Distribution(%)		64.08%	LN 5 / LN 3
7				
8	Non-Distribution	$	382,673	Company Analysis
9	Peak Period	$	346,780	Company Analysis
10	Off-Peak Period	$	35,005	Company Analysis
11	Peak Period (%)		90.62%	LN 9 / LN 8
12				
13	**Forecast Bad Debt Expense 12 Months Ended July 31, 2012**			
14				
15	Annual Total	$	650,000	Company Analysis
16	Annual Non-Distribution	$	416,526	LN 15* LN 6
17	Peak Non-Distribution	**$**	**377,457**	LN 16 * LN 11

Schedule 4

Reserved for future use

Unitil
Northern Utilities, Inc.

RESERVED FOR FUTURE USE

Schedule 5A, Attachment, 5B, and 5C

Northern Utilities, Inc.

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2011 through October 31, 2012			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 10,419,440	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 30,740,112	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,062,730	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,303,860	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 508,750	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (4,400,490)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 41,634,403	Sum Lines 1 through 6.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2011 through October 31, 2012

Pipeline	Contract ID	Rate	Negotiated Rate	MDQ (Dth)	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Months Per Year	Support for Demand Rate	Monthly Demand	Annual Demand
Algonquin	93002F	AFT-1 (AFT-2)	No	4,211	Mendon, MA	Brockton, MA	$ 6.1138	12	Line 1 of Page 2, Att to Sch 5A	$ 25,745	$ 308,943
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	1,251	Centerville, NJ	Taunton, MA	$ 5.9771	12	Line 2 of Page 2, Att to Sch 5A	$ 7,477	$ 89,728
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.1000	12	Line 3 of Page 2, Att to Sch 5A	$ 310,000	$ 3,720,000
Iroquois	R181001	RTS-1	No	6,569	Zone 1	Zone 1	$ 6.5971	12	Line 4 of Page 2, Att to Sch 5A	$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Pittsburgh	GSGT	$ 40.2456	12	Line 5 of Page 2, Att to Sch 5A	$ 44,270	$ 531,242
PNGTS	1997-004	FT	Yes	33,000	Pittsburgh	GSGT	$ 76.4666	5	Line 6 of Page 2, Att to Sch 5A	$ 2,523,398	$ 12,616,989
Tennessee	5083	FT-A	No	4,605	Zone 0	Zone 6	$ 33.0885	12	Line 7 of Page 2, Att to Sch 5A	$ 152,373	$ 1,828,471
Tennessee	5083	FT-A	No	8,550	Zone L	Zone 6	$ 29.4677	12	Line 8 of Page 2, Att to Sch 5A	$ 251,949	$ 3,023,386
Tennessee	5265	FT-A	No	2,653	Zone 4	Zone 6	$ 12.1681	12	Line 9 of Page 2, Att to Sch 5A	$ 32,282	$ 387,384
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 10.7923	12	Line 10 of Page 2, Att to Sch 5A	$ 15,174	$ 182,088
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 10.7923	12	Line 10 of Page 2, Att to Sch 5A	$ 24,024	$ 288,284
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 10.7923	12	Line 10 of Page 2, Att to Sch 5A	$ 10,026	$ 120,313
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 10.7923	12	Line 10 of Page 2, Att to Sch 5A	$ 46,051	$ 552,609
Tennessee	46314	FT-A	No	950	Zone 5	Zone 6	$ 10.7923	5	Line 10 of Page 2, Att to Sch 5A	$ 10,253	$ 51,263
Texas Eastern	800464	CDS	No	33	ELA	M1	$ 2.3701	12	Line 11 of Page 2, Att to Sch 5A	$ 78	$ 939
Texas Eastern	800464	CDS	No	9	ETX	M1	$ 2.1665	12	Line 12 of Page 2, Att to Sch 5A	$ 19	$ 234
Texas Eastern	800464	CDS	No	16	STX	M1	$ 6.7878	12	Line 13 of Page 2, Att to Sch 5A	$ 109	$ 1,303
Texas Eastern	800464	CDS	No	18	WLA	M1	$ 2.8175	12	Line 14 of Page 2, Att to Sch 5A	$ 51	$ 609
Texas Eastern	800464	CDS	No	59	M1	M3	$ 10.9950	12	Line 15 of Page 2, Att to Sch 5A	$ 649	$ 7,784
Texas Eastern	800436	CDS	No	64	M3	M3	$ 5.2810	12	Line 16 of Page 2, Att to Sch 5A	$ 338	$ 4,056
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.7180	12	Line 17 of Page 2, Att to Sch 5A	$ 5,518	$ 66,214
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 35.4197	12	Line 18 of Page 2, Att to Sch 5A	$ 1,204,270	$ 14,451,238
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 13.5608	12	Line 19 of Page 2, Att to Sch 5A	$ 80,510	$ 966,126
Union	M12205	M12	No	6,003	Dawn	Parkway	$ 2.5670	12	Line 20 of Page 2, Att to Sch 5A	$ 15,410	$ 184,916
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	Line 21 of Page 2, Att to Sch 5A	$ 130,579	$ 1,566,952
Vector	CRL-NUI-0727	FT-1	Yes	17,086	W-10	Dawn	$ 4.5625	5	Line 22 of Page 2, Att to Sch 5A	$ 77,955	$ 389,774
Vector	FT-1-NUI-0122	FT-1	Yes	6,070	Alliance	St. Clair	$ 7.7745	12	Line 23 of Page 2, Att to Sch 5A	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	$ 0.4975	12	Line 24 of Page 2, Att to Sch 5A	$ 3,020	$ 36,238

Total Annual Demand Costs $ 42,463,412

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2011 through October 31, 2012

Pipeline	Contract ID	MDQ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Algonquin	93002F	4,211	4,211			100%	0%	0%	$ 308,943	$ 308,943	$ -	$ -
Algonquin	93201A1C	1,251	1,166	85		93%	7%	0%	$ 89,728	$ 83,632	$ 6,097	$ -
Granite	10-010-FT-NN	100,000	29,421	35,529	35,050	29%	36%	35%	$ 3,720,000	$ 1,094,461	$ 1,321,679	$ 1,303,860
Iroquois	R181001	6,569	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	1,100			100%	0%	0%	$ 531,242	$ 531,242	$ -	$ -
PNGTS	1997-004	33,000		33,000		0%	100%	0%	$ 12,616,989	$ -	$ 12,616,989	$ -
Tennessee	5083	4,605	4,605			100%	0%	0%	$ 1,828,471	$ 1,828,471	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 3,023,386	$ 3,023,386	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 387,384	$ -	$ 387,384	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 182,088	$ 182,088	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 288,284	$ 288,284	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 120,313	$ 120,313	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 552,609	$ 552,609	$ -	$ -
Tennessee	46314	950	950	-		100%	0%	0%	$ 51,263	$ 51,263	$ -	$ -
Texas Eastern	800464	33	33			100%	0%	0%	$ 939	$ 939	$ -	$ -
Texas Eastern	800464	9	9			100%	0%	0%	$ 234	$ 234	$ -	$ -
Texas Eastern	800464	16	16			100%	0%	0%	$ 1,303	$ 1,303	$ -	$ -
Texas Eastern	800464	18	18			100%	0%	0%	$ 609	$ 609	$ -	$ -
Texas Eastern	800464	59	59			100%	0%	0%	$ 7,784	$ 7,784	$ -	$ -
Texas Eastern	800436	64	64	-		100%	0%	0%	$ 4,056	$ 4,056	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 66,214	$ 66,214	$ -	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 14,451,238	$ -	$ 14,451,238	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 966,126	$ 966,126	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 184,916	$ 184,916	$ -	$ -
Vector	CRL-NUI-0725	17,172		17,172		0%	100%	0%	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086		17,086		0%	100%	0%	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	6,070	-		100%	0%	0%	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,070	6,070	-		100%	0%	0%	$ 36,238	$ 36,238	$ -	$ -
Annual Total Demand Costs									$ 42,463,412	$ 10,419,440	$ 30,740,112	$ 1,303,860

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2011 through October 31, 2012

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Support for Demand Rates	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0250	$ 1.8100	12	Line 1 of Page 3, Att to Sch 5A	$ 77,801	$ 92,158	$ 169,959
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.5480	12	Line 2 of Page 3, Att to Sch 5A	$ 189	$ 1,398	$ 1,587
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	Line 3 of Page 3, Att to Sch 5A	$ 497	$ 687	$ 1,184
W-10	01052	Storage	Yes	3,400,000		34,000			12	Line 4 of Page 3, Att to Sch 5A	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges $ 3,062,730

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2011 through October 31, 2012

Resource	Contract Quantity	Maximum Daily Quantity	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Fixed Charges
LNG Supply	125,000	5,000	5	Line 1 of Page 4, Att to Sch 5A	$ 74,750	[redacted]
Peaking Supply 1	1,080,000	12,000	3	Line 2 of Page 4, Att to Sch 5A	$ 40,000	
Peaking Supply 2	50,000	10,000	5	Line 3 of Page 4, Att to Sch 5A	$ 3,000	
Peaking Supply 3	50,000	10,000	5	Line 4 of Page 4, Att to Sch 5A	$ -	
Total Peaking Supply Contract Demand Costs						$ 508,750

REDACTED

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2011 through October 31, 2012

Asset Management Agreeement Revenue	
Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	[redacted]
Wash 10 via Vector, TCPL, PNGTS	
Tennessee Niagara	
Tennessee Long-Haul	
Total Asset Management	$ (4,087,000)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (66,701)
AGT Contract 93201A1C	$ (98,779)
Tennessee 5265	$ (103,375)
Granite 10-010-FT-NN	$ (27,675)
Granite 10-010-FT-NN	$ (12,160)
Granite 10-010-FT-NN	$ (4,800)
Total Capacity Release	$ (313,490)

Total Asset Management and Capacity Release Revenue	$ (4,400,490)

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for September 6, 2011

Estimated Adders to NYMEX Last Day Settlement

Line		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
1	CHICAGO	$0.209	$0.209	$0.209	$0.209	$0.209	$0.063
2	PNGTS	$1.900	$1.900	$1.900	$1.900	$1.900	$0.360
3	LEWISTON	$1.940	$1.940	$1.940	$1.940	$1.940	$0.380
4	NIAGARA	$0.641	$0.641	$0.641	$0.641	$0.641	$0.357
5	TGP Z0	($0.079)	($0.079)	($0.079)	($0.079)	($0.079)	($0.079)
6	TGP Z1	($0.034)	($0.034)	($0.034)	($0.034)	($0.034)	($0.034)
7	TGP Z4	$0.210	$0.210	$0.210	$0.210	$0.210	$0.210
8	PEAK 1	$9.028	$9.028	$9.028	$9.028	$9.028	NA
9	PEAK 2	$9.506	$9.506	$9.506	$9.506	$9.506	NA
10	PEAK 3	NA	$9.479	$9.479	$9.479	NA	NA
11	LNG	$0.428	$1.793	$3.184	$3.004	$0.907	$0.395
12	W10 Supply	$0.209	$0.209	$0.209	$0.209	$0.209	$0.063
13	W10 AMA Spot	$0.678	$2.043	$3.434	$3.254	$1.157	$0.645
14							
15	NYMEX NG	$4.043	$4.259	$4.383	$4.390	$4.359	$4.344

Northern Utilities, Inc.
Transportation Contract Rates

Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Demand Rate Support	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 7	$ 5.9771	$ 5.9771	$ 5.9771	$ 5.9771	$ 5.9771	$ 5.9771
3	Granite	FT-NN	N/A	N/A		Page 8	$ 3.1000	$ 3.1000	$ 3.1000	$ 3.1000	$ 3.1000	$ 3.1000
4	Iroquois	RTS-1	Zone 1	Zone 1		Page 9	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971
5	PNGTS	FT	N/A	N/A		Page 17	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456
6	PNGTS	FT (Seasonal)	N/A	N/A	1	Page 17	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666	
7	Tennessee	FT-A	Zone 0	Zone 6		Page 19	$ 33.0885	$ 33.0885	$ 33.0885	$ 33.0885	$ 33.0885	$ 33.0885
8	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 29.4677	$ 29.4677	$ 29.4677	$ 29.4677	$ 29.4677	$ 29.4677
9	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 12.1681	$ 12.1681	$ 12.1681	$ 12.1681	$ 12.1681	$ 12.1681
10	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 10.7923	$ 10.7923	$ 10.7923	$ 10.7923	$ 10.7923	$ 10.7923
11	Texas Eastern	CDS	ELA	M1		Page 23	$ 2.3701	$ 2.3701	$ 2.3701	$ 2.3701	$ 2.3701	$ 2.3701
12	Texas Eastern	CDS	ETX	M1		Page 23	$ 2.1665	$ 2.1665	$ 2.1665	$ 2.1665	$ 2.1665	$ 2.1665
13	Texas Eastern	CDS	STX	M1		Page 23	$ 6.7878	$ 6.7878	$ 6.7878	$ 6.7878	$ 6.7878	$ 6.7878
14	Texas Eastern	CDS	WLA	M1		Page 23	$ 2.8175	$ 2.8175	$ 2.8175	$ 2.8175	$ 2.8175	$ 2.8175
15	Texas Eastern	CDS	M1	M3		Page 23	$ 10.9950	$ 10.9950	$ 10.9950	$ 10.9950	$ 10.9950	$ 10.9950
16	Texas Eastern	CDS	M3	M3		Page 23	$ 5.2810	$ 5.3070	$ 5.3070	$ 5.3070	$ 5.3070	$ 5.3070
17	Texas Eastern	FT-1/FTS	M3	M3	2	Pages 23, 24	$ 5.7180	$ 5.7440	$ 5.7440	$ 5.7440	$ 5.7440	$ 5.7440
18	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 35.4197	$ 35.4197	$ 35.4197	$ 35.4197	$ 35.4197	$ 35.4197
19	TransCanada	FT	Parkway	Iroquois		Page 26	$ 13.5608	$ 13.5608	$ 13.5608	$ 13.5608	$ 13.5608	$ 13.5608
20	Union	M12	Dawn	Parkway		Page 26	$ 2.5670	$ 2.5670	$ 2.5670	$ 2.5670	$ 2.5670	$ 2.5670
21	Vector	FT-1	Alliance	Dawn		Page 36	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042
22	Vector	FT-1	W-10	Dawn	3	Pages 33, 34	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	
23	Vector	FT-1	Alliance	St. Clair	4	Page 37	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745
24	Vector Canada	FT-1	St. Clair	Dawn		Page 26	$ 0.5089	$ 0.5089	$ 0.5089	$ 0.5089	$ 0.5089	$ 0.5089

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Commodity Rate Support	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
25	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 5	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131
27	Granite	FT-NN	N/A	N/A		Page 8	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
28	Iroquois	RTS-1	Zone 1	Zone 1	5	Pages 9, 11	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052
29	LNG Trucking		Everett, MA	Lewiston, ME		Page 13	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900
30	PNGTS	FT	N/A	N/A		Page 17	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
31	Tennessee	FT-A	Zone 0	Zone 4		Page 20	$ 0.0987	$ 0.0987	$ 0.0987	$ 0.0987	$ 0.0987	$ 0.0987
32	Tennessee	FT-A	Zone 0	Zone 6		Page 20	$ 0.1356	$ 0.1356	$ 0.1356	$ 0.1356	$ 0.1356	$ 0.1356
33	Tennessee	FT-A	Zone L	Zone 4		Page 20	$ 0.0831	$ 0.0831	$ 0.0831	$ 0.0831	$ 0.0831	$ 0.0831
34	Tennessee	FT-A	Zone L	Zone 6		Page 20	$ 0.1178	$ 0.1178	$ 0.1178	$ 0.1178	$ 0.1178	$ 0.1178
35	Tennessee	FT-A	Zone 4	Zone 6		Page 20	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368
36	Tennessee	FT-A	Zone 5	Zone 6		Page 20	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269
37	Texas Eastern	CDS	ELA	M3		Page 23	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534
38	Texas Eastern	CDS	ETX	M3		Page 23	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534
39	Texas Eastern	CDS	STX	M3		Page 23	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534
40	Texas Eastern	CDS	WLA	M3		Page 23	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534	$ 0.0534
41	Texas Eastern	FT-1/FTS	M3	M3		Page 23	$ 0.0156	$ 0.0156	$ 0.0156	$ 0.0156	$ 0.0156	$ 0.0156
42	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 0.0339	$ 0.0339	$ 0.0339	$ 0.0339	$ 0.0339	$ 0.0339
43	TransCanada	FT	Parkway	Iroquois		Page 26	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113
44	Union	M12	Dawn	Parkway		Page 26	$ -	$ -	$ -	$ -	$ -	$ -
45	Vector	FT-1	Alliance	W-10 Storage		Page 34	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Vector	FT-1	Alliance	Dawn		Page 34	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
47	Vector	FT-1	W-10 Storage	Dawn		Page 34	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019

Transportation Fuel Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Fuel Rate Support	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
48	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 6	0.72%	1.02%	1.02%	1.02%	1.02%	0.72%
49	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 6	0.72%	1.02%	1.02%	1.02%	1.02%	0.72%
50	Granite	FT-NN	N/A	N/A		Page 8	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
51	Iroquois	RTS-1	Zone 1	Zone 1	6	Page 12	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%
52	PNGTS	FT	N/A	N/A	7	Page 18	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
53	Tennessee	FT-A	Zone 0	Zone 4		Page 21	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
54	Tennessee	FT-A	Zone 0	Zone 6		Page 21	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%
55	Tennessee	FT-A	Zone L	Zone 4		Page 21	2.45%	2.45%	2.45%	2.45%	2.45%	2.45%
56	Tennessee	FT-A	Zone L	Zone 6		Page 21	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
57	Tennessee	FT-A	Zone 4	Zone 6		Page 21	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
58	Tennessee	FT-A	Zone 5	Zone 6		Page 21	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%
59	Texas Eastern	CDS	ELA	M3		Page 24	6.79%	7.71%	7.71%	7.71%	7.71%	6.79%
60	Texas Eastern	CDS	ETX	M3		Page 24	6.79%	7.71%	7.71%	7.71%	7.71%	6.79%
61	Texas Eastern	CDS	STX	M3		Page 24	7.88%	8.99%	8.99%	8.99%	8.99%	7.88%
62	Texas Eastern	CDS	WLA	M3		Page 24	7.12%	8.10%	8.10%	8.10%	8.10%	7.12%
63	Texas Eastern	FT-1/FTS	M3	M3		Page 24	2.30%	2.59%	2.59%	2.59%	2.59%	2.30%
64	TransCanada	FT	Dawn	E. Hereford	6	Page 38	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%
65	TransCanada	FT	Parkway	Iroquois	6	Page 38	1.12%	1.12%	1.12%	1.12%	1.12%	1.12%
66	Union	M12	Dawn	Parkway		Page 32	1.14%	1.14%	1.14%	1.14%	1.14%	1.14%
67	Vector	FT-1	Alliance	W-10 Storage	6	Page 39	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%
68	Vector	FT-1	Alliance	Dawn	6	Page 39	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%
69	Vector	FT-1	W-10 Storage	Dawn	6	Page 39	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%

Note 1 Applicable Nov through Mar only.
Note 2 FT-1 Demand Rate = $5.0580 plus FT-1 / FTS Rate = $0.66, totals to $5.718.
Note 3 Applicable Nov through Mar only.
Note 4 Negotiated Rate Agreement = $8.0908 per Dth, which is higher than max rate, so max rate prevails.
Note 5 RTS-1 Commodity Rate = $0.003 per Dth; ACA = $0.0019 per Dth and Zone 1 Deferred Asset Charge = $0.0003. Total equals $0.052
Note 6 Fuel Rates Estiamted based on 12 months historic averages.
Note 7 12 Months Historic Average Fuel Rate is below 0%; 0% Fuel Rate assumed for estimation puposes.

Northern Utilities, Inc. Underground Storage Contract Rates										
Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		Page 22	$ 0.0250	$ 1.8100	$ 0.0204	0.00%	$ 0.0204	1.59%
2	Texas Eastern	SS-1		Page 24	$ 0.1293	$ 5.5480				
3	Texas Eastern	FSS-1		Page 24	$ 0.1293	$ 0.8950				
4	W-10	Storage		Pages 40, 41, 42			$ -	0.50%	$ -	1.10%

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Northern Utilities, Inc. Peaking Supply Demand Cost				
Line	Peaking Supply Contract	Notes	Reference	Monthly Demand Cost
1	LNG Supply		Page 43	[redacted]
2	Peaking Supply 1		Page 44	
3	Peaking Supply 2	1		
4	Peaking Supply 3		Page 45	

Note 1 Contract for Peaking Supply 2 is pending.

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2010

•RATE SCHEDULE AFT-1

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release 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

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release 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

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release 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	$ 4.6346	$0.0019	$0.0019	$0.1543	$0.0019	$0.1524
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun 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	$0.1543	$0.0019	$0.1543	$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

ALGONQUIN GAS TRANSMISSION, LLC
DISCOUNTED RATE LETTER - SCHEDULE

Customer Name	Contract Number	Contract Begin Date	Contract End Date	Rate Schedule	Discounted Rate	Recourse Reservation Rate	Recourse Usage Rate
NORTHERN UTILITIES, INC.	93201A1C	12/1/1997	10/31/2012	AFT-12	$ 5.9771	$ 6.5734	$ 0.0112

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

	$/Dth		
	Base Tariff Rate	ACA Adj.	Total Current Rate
Reservation Charge:			
Maximum	$3.1000		$3.1000
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	$0.1019	$0.0019	$0.1038
Minimum	$0.0000	$0.0019	$0.0019
Fuel and Losses Percentage			0.35%
Volumetric Reservation Charge			
Maximum	$0.1019	$0.0019	$0.1038
Minimum	$0.0000	$0.0019	$0.0019

Iroquois Gas Transmission System, L.P.
FERC Gas Tariff
Second Revised Volume No. 1

--------------- 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

(Footnotes continued on Sheet 4.01)

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.

4/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

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%

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Average
Iroquois	Zone 1	Zone 1	0.00%	0.00%	0.10%	0.10%	0.20%	0.30%	0.30%	0.50%	0.60%	0.40%	0.00%	0.00%	0.21%

Line	Item	Value	Reference
1	LNG Trucking Rate	[redacted]	Page 14
2	Diesel Adjustment		
3	Current Diesel Rate per Gallon		Page 16
4	Forecast Diesel Rate per Gallon		Estimate
5	Diesel Fuel Adjustment per Load		Page 15
6	Average Load (Dth)		
7	Diesel Fuel Adjustment per Dth		Line 5 divided by Line 6
8			
9	Average LNG Trucking Cost	$ 0.99	Line 1 plus Line 7

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LNG TRANSPORTATION RATE AGREEMENT

DATE: June 24, 2010

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CARRIER:

[redacted]

SHIPPER:

Northern Utilities Inc.
d/b/a Unitil Services Corp.
6 Liberty Lane West
Hampton, NH 03842

EFFECTIVE DATE: 11/01/10

EXPIRATION DATE: 10/31/11

ORIGIN	DESTINATION	COMMODITY DATE	RATE
Everett, MA	Lewiston, ME	11/01/10 to 10/31/11	[redacted]

OTHER TERMS AND CONDITIONS:

[redacted]

4. This agreement is strictly confidential.

CARRIER: [redacted]

By: Martin DeBruin

Martin DeBruin

Its: **Director of Customer Relations**

SHIPPER: **Northern Utilities Inc.**

By:

Robert Furino

Its: **Director of Energy Contracts**

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[redacted]

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EXHIBIT 2

DIESEL FUEL ADJUSTMENT TABLE

If the DOE posted price per gallon for diesel fuel is:	The surcharge per load will be:
[redacted]	[redacted]

The diesel fuel price referenced above is the price posted by the U.S. Department of Energy on the Energy Information Administration website at http://tonto.eia.doe.gov/oog/info/wohdp/diesel.asp for the "Weekly Retail On-Highway Diesel Prices for New England" published each Monday, and the corresponding surcharge applies for the 7-day period commencing on that Monday.

[redacted]

Experience you can count on

H:\Fitchburg\Unitil 100512 Lewiston DFA Table F.doc

U.S. Energy Information Administration

Home > Petroleum > Weekly Retail On-Highway Diesel Prices

Weekly Retail On-Highway Diesel Prices *

Weekly Retail On-Highway Diesel Prices
(Dollars per gallon, including all taxes)

Region	07/18/11	07/25/11	08/01/11	Change from week ago	Change from year ago
U.S.	3.923	3.949	3.937	-0.012	1.009
East Coast	3.963	3.988	3.974	-0.014	1.040
New England	4.034	4.037	4.045	0.008	1.036
Central Atlantic	4.066	4.090	4.090	0.000	1.070
Lower Atlantic	3.912	3.940	3.918	-0.022	1.028
Midwest	3.903	3.925	3.918	-0.007	1.018
Gulf Coast	3.882	3.913	3.904	-0.009	1.017
Rocky Mountain	3.827	3.848	3.855	0.007	0.918
West Coast	4.005	4.038	4.000	-0.038	0.929
California	4.114	4.145	4.136	-0.009	1.004

Click on a Region to view graph of that Region

U.S. East Coast New England Central Atlantic Lower Atlantic
Midwest Gulf Coast Rocky Mountain West Coast California

Release Schedule
Printer-Friendly Version
Sign-up for email notification
24-hour hotline: 202-586-6966

Reference

Prices for Last 53 Weeks (html) (text)
Spreadsheet of Complete Diesel Historical Data (.xls)
Diesel Fuel Taxes
Does EIA Calculate Diesel Fuel Surcharges?
States in each Region
Data Collection Procedures and Statistical Methodology
Coefficient of Variation Report

Related Links

This Week in Petroleum
Gasoline and Diesel Fuel Update
A Primer on Diesel Fuel Prices
Real Petroleum Prices (CPI Adjusted)
Petroleum Navigator
Diesel Regulations
U.S. Retail Gasoline Prices

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 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Average
PNGTS	N/A	N/A	-0.70%	-0.70%	-0.70%	-0.70%	-0.70%	-0.70%	-0.70%	-0.70%	-0.70%	-0.50%	0.00%	0.00%	-0.57%

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$7.8388		$15.0198	$19.7726	$20.1004	$25.1838	$26.6698	$33.0885
L		$7.0992						
1	$11.3219		$10.7586	$13.9042	$19.1763	$21.6140	$24.2473	$29.4677
2	$19.7726		$13.8422	$7.7920	$7.3650	$10.1388	$13.5681	$17.1056
3	$20.1004		$11.2131	$7.8416	$6.0071	$9.5356	$16.4342	$18.7169
4	$25.1838		$23.0587	$9.7077	$14.0281	$8.3057	$8.9007	$12.1681
5	$29.7879		$21.3027	$10.0699	$11.9223	$9.1155	$8.6128	$10.7923
6	$34.2674		$24.2865	$17.1056	$18.7169	$15.2862	$8.4620	$7.4442

Daily Base Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.2577		$0.4938	$0.6501	$0.6608	$0.8280	$0.8768	$1.0878
L		$0.2334						
1	$0.3722		$0.3537	$0.4571	$0.6305	$0.7106	$0.7972	$0.9688
2	$0.6501		$0.4551	$0.2562	$0.2421	$0.3333	$0.4461	$0.5624
3	$0.6608		$0.3686	$0.2578	$0.1975	$0.3135	$0.5403	$0.6154
4	$0.8280		$0.7581	$0.3192	$0.4612	$0.2731	$0.2926	$0.4000
5	$0.9793		$0.7004	$0.3311	$0.3920	$0.2997	$0.2832	$0.3548
6	$1.1266		$0.7985	$0.5624	$0.6154	$0.5026	$0.2782	$0.2447

Maximum Reservation Rates 2 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$7.8388		$15.0198	$19.7726	$20.1004	$25.1838	$26.6698	$33.0885
L		$7.0992						
1	$11.3219		$10.7586	$13.9042	$19.1763	$21.6140	$24.2473	$29.4677
2	$19.7726		$13.8422	$7.7920	$7.3650	$10.1388	$13.5681	$17.1056
3	$20.1004		$11.2131	$7.8416	$6.0071	$9.5356	$16.4342	$18.7169
4	$25.1838		$23.0587	$9.7077	$14.0281	$8.3057	$8.9007	$12.1681
5	$29.7879		$21.3027	$10.0699	$11.9223	$9.1155	$8.6128	$10.7923
6	$34.2674		$24.2865	$17.1056	$18.7169	$15.2862	$8.4620	$7.4442

Notes:
1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge of $0.00 for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions.

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	$0.0083		$0.0305	$0.0469	$0.0582	$0.0702	$0.0797	$0.0974
L		$0.0031						
1	$0.0110		$0.0215	$0.0390	$0.0475	$0.0589	$0.0720	$0.0845
2	$0.0469		$0.0231	$0.0029	$0.0073	$0.0156	$0.0281	$0.0401
3	$0.0582		$0.0475	$0.0073	$0.0006	$0.0226	$0.0332	$0.0460
4	$0.0702		$0.0544	$0.0229	$0.0278	$0.0077	$0.0130	$0.0259
5	$0.0797		$0.0720	$0.0281	$0.0332	$0.0129	$0.0127	$0.0187
6	$0.0974		$0.0845	$0.0401	$0.0460	$0.0242	$0.0115	$0.0056

Minimum
Commodity Rates 1/, 2/ 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0132		$0.0438	$0.0665	$0.0821	$0.0987	$0.1118	$0.1356
L		$0.0060						
1	$0.0169		$0.0314	$0.0556	$0.0673	$0.0831	$0.1012	$0.1178
2	$0.0665		$0.0336	$0.0057	$0.0118	$0.0233	$0.0405	$0.0564
3	$0.0821		$0.0673	$0.0118	$0.0025	$0.0329	$0.0476	$0.0646
4	$0.0987		$0.0769	$0.0334	$0.0401	$0.0123	$0.0197	$0.0368
5	$0.1118		$0.1012	$0.0405	$0.0476	$0.0195	$0.0193	$0.0269
6	$0.1356		$0.1178	$0.0564	$0.0646	$0.0345	$0.0169	$0.0088

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0132		$0.0438	$0.0665	$0.0821	$0.0987	$0.1118	$0.1356
L		$0.0060						
1	$0.0169		$0.0314	$0.0556	$0.0673	$0.0831	$0.1012	$0.1178
2	$0.0665		$0.0336	$0.0057	$0.0118	$0.0233	$0.0405	$0.0564
3	$0.0821		$0.0673	$0.0118	$0.0025	$0.0329	$0.0476	$0.0646
4	$0.0987		$0.0769	$0.0334	$0.0401	$0.0123	$0.0197	$0.0368
5	$0.1118		$0.1012	$0.0405	$0.0476	$0.0195	$0.0193	$0.0269
6	$0.1356		$0.1178	$0.0564	$0.0646	$0.0345	$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 0.09%.

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 (F&LR) 1/,2/,3/,4/

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.43%		1.32%	1.97%	2.42%	2.90%	3.28%	3.91%
L		0.22%						
1	0.54%		0.96%	1.65%	1.99%	2.45%	2.97%	3.40%
2	1.97%		1.02%	0.22%	0.39%	0.72%	1.22%	1.63%
3	2.42%		1.99%	0.39%	0.12%	1.00%	1.42%	1.86%
4	2.90%		2.27%	1.01%	1.21%	0.41%	0.62%	1.06%
5	3.28%		2.97%	1.22%	1.42%	0.61%	0.61%	0.77%
6	3.91%		3.40%	1.63%	1.86%	0.99%	0.49%	0.25%

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.09%.
2/ for service that is rendered entirely by displacement, shipper shall render only the quantity of gas associated with Losses of 0.09%.
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.

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/	1.59%
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/	1.59%
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 0.09%.

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

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

PROPOSED EFFECTIVE RATES 8/01/2011

•RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.7878	6.5648	2.7220
WLA-AAB	2.8175	2.5945	1.1300
ELA-AAB	2.3701	2.1471	0.9500
ETX-AAB	2.1665	1.9435	0.8760
STX-STX	5.7236	5.5006	2.2920
STX-WLA	5.8820	5.6590	2.3560
STX-ELA	6.7928	6.5698	2.7220
STX-ETX	6.7928	6.5698	2.7220
WLA-WLA	2.0525	1.8295	0.8220
WLA-ELA	2.8225	2.5995	1.1300
WLA-ETX	2.8225	2.5995	1.1300
ELA-ELA	2.3731	2.1501	0.9500
ETX-ETX	2.1695	1.9465	0.8760
ETX-ELA	2.3555	2.1325	0.9500
M1-M1	4.5230	4.3000	1.8070
M1-M2	8.3700	8.1470	3.3440
M1-M3	10.9950	10.7720	4.3940
M2-M2	6.5020	6.2790	2.5980
M2-M3	9.2650	9.0420	3.7020
M3-M3	5.2810	5.0580	2.1100

7(C) RATE SCHEDULES	
FTS	5.3500
FTS-2	7.9590
FTS-4	7.7250
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	0.0040
M1-M3	0.0050

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0000	0.0000	0.0000	0.0000	0.0112	0.0367	0.0534
from WLA		0.0000	0.0000	0.0000	0.0112	0.0367	0.0534
from ELA			0.0000	0.0000	0.0112	0.0367	0.0534
from ETX				0.0000	0.0112	0.0367	0.0534
from M1					0.0112	0.0367	0.0534
from M2						0.0240	0.0412
from M3							0.0156

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	0.0346	0.0309	0.0293	0.0293	0.0206		
from M2	0.0682	0.0645	0.0629	0.0629	0.0542	0.0378	
from M3	0.0912	0.0875	0.0859	0.0859	0.0772	0.0608	0.0272

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1811	0.1863	0.2164	0.2164	0.3687	0.5206	0.6235
from WLA		0.0602	0.0856	0.0856	0.2379	0.3898	0.4927
from ELA			0.0708	0.0708	0.2231	0.3750	0.4779
from ETX				0.0646	0.2170	0.3689	0.4718
from M1					0.1524	0.3043	0.4072
from M2						0.2302	0.3382
from M3							0.1817

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1899						
from WLA	0.1959	0.0661					
from ELA	0.2304	0.0959	0.0795				
from ETX	0.2304	0.0959	0.0795	0.0733			
from M1	0.3891	0.2576	0.2412	0.2351	0.1618		
from M2	0.5521	0.4176	0.4012	0.3951	0.3218	0.2440	
from M3	0.6613	0.5268	0.5104	0.5043	0.4310	0.3578	0.1933

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1812	0.1864	0.2166	0.2166	0.3692	0.5211	0.6242
from WLA		0.0603	0.0857	0.0857	0.2383	0.3902	0.4933
from ELA			0.0709	0.0709	0.2235	0.3754	0.4785
from ETX				0.0647	0.2173	0.3692	0.4723
from M1					0.1526	0.3045	0.4076
from M2						0.2304	0.3385
from M3							0.1819

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1900						

from WLA	0.1960	0.0662					
from ELA	0.2306	0.0960	0.0796				
from ETX	0.2306	0.0960	0.0796	0.0734			
from M1	0.3926	0.2580	0.2416	0.2354	0.1620		
from M2	0.5526	0.4180	0.4016	0.3954	0.3220	0.2442	
from M3	0.6620	0.5274	0.5110	0.5048	0.4314	0.3581	0.1935

•OTHER TRANSPORTATION SERVICES

	Reservation	Usage-1	Shrinkage In Path	Shrinkage Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3410 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	0.6600		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	10.2010		0.37%	
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	14.5169		4.28%	4.69%
FT-1/TME2	23.3313		3.69%	4.63%
FT-1/TME3	23.4630		0.75%	
MLS-1/FH	0.6340		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	0.0305 3/	0.01%	
MLS-1/HS	6.1130	0.2010 3/	0.01%	

		Primary Rec Pt	Secondary Rec Pt
FT-1/TMX	19.0730	0.64%	Winter 4.30%/Summer 3.73%

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

•STORAGE SERVICES

	RES.	SPACE	INJ.	WITH.
SS	5.4290	0.1293	0.0267	0.0394
SS-1	5.5260	0.1293	0.0267	0.0393
X-28	4.8300	0.1293	0.0267	0.0351
FSS-1	0.8950	0.1293	0.0267	0.0267
ISS-1		0.0323	0.1824	0.0267

•SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.35%	2.54%	3.59%	3.59%	5.79%	7.72%	8.99%
from WLA	1.64%	1.64%	2.70%	2.70%	4.90%	6.83%	8.10%
from ELA	2.31%	2.31%	2.31%	2.31%	4.51%	6.44%	7.71%
from ETX	2.35%	2.31%	2.31%	2.31%	4.51%	6.44%	7.71%
from M1					2.20%	4.13%	5.40%
from M2						3.20%	4.50%
from M3							2.59%

April 1 through November 30

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.10%	2.27%	3.16%	3.16%	5.13%	6.79%	7.88%
from WLA	1.49%	1.49%	2.40%	2.40%	4.37%	6.03%	7.12%
from ELA	2.07%	2.07%	2.07%	2.07%	4.04%	5.70%	6.79%
from ETX	2.10%	2.07%	2.07%	2.07%	4.04%	5.70%	6.79%
from M1					1.97%	3.63%	4.72%
from M2						2.83%	3.94%
from M3							2.30%

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	3.34%	3.09%
FSS-1,ISS-1	0.97%	0.97%
INJECTIONS	0.97%	0.97%
INVENTORY LEVEL	0.07%	0.07%

- **SURCHARGES**

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 ACA Surcharge
Commodity  0.0019
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- **The Summary of Rates serves as a handy reference and does not replace Texas Eastern's Tariff.**

Canadian Fixed Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Demand Toll	$CAD / GJ	$ 11.44984	Page 30
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.86987	Page 28
4	Total Demand Toll	$CAD / GJ	$ 12.31971	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.0433	Page 27
6	Total Demand Toll	$US / GJ	$ 12.8532	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Total Demand Toll	$US / Dth	$ 13.5608	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Demand Toll	$CAD / GJ	$ 25.65149	Page 29
12	Union Dawn Surcharge	$CAD / GJ	$ 0.14372	Page 28
13	Delivery Pressure Demand Toll	$CAD / GJ	$ 6.38290	Page 28
14	Total Demand Toll	$CAD / GJ	$ 32.17811	Sum Lines Above.
15	$CAD to $US	Ratio	1.0433	Page 27
16	Total Demand Toll	$US / GJ	$ 33.5714	Line 13 times Line 14
17	GJ per Dth	Ratio	1.0551	
18	Total Demand Toll	$US / Dth	$ 35.4197	Line 15 divided by Line 16
19				
20	Dawn to Parkway on Union Pipeline			
21	Total Demand Toll	$CAD / GJ	$ 2.3320	Page 31
22	$CAD to $US	Ratio	1.0433	Page 27
23	Total Demand Toll	$US / GJ	$ 2.4330	Line 13 times Line 14
24	GJ per Dth	Ratio	1.0551	
25	Total Demand Toll	$US / Dth	$ 2.5670	Line 15 divided by Line 16
26				
27	St. Clair to Dawn on Vector Canada			
28	Total Demand Toll	$CAD / GJ	$ 0.4623	Page 35
29	$CAD to $US	Ratio	1.0433	Page 27
30	Total Demand Toll	$US / GJ	$ 0.4823	Line 13 times Line 14
31	GJ per Dth	Ratio	1.0551	
32	Total Demand Toll	$US / Dth	$ 0.5089	Line 15 divided by Line 16

Canadian Variable Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Variable Toll	$CAD / GJ	$ 0.01029	Page 30
3	Delivery Pressure Commodity Toll	$CAD / GJ	$ -	Page 28
4	Variable Transportation Rate	$CAD / GJ	$ 0.01029	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.0433	Page 27
6	Variable Transportation Rate	$US / GJ	$ 0.0107	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ 0.0113	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Commodity Rate	$CAD / GJ	$ 0.02536	Page 29
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ 0.00537	Page 28
13	Variable Transportation Rate	$CAD / GJ	$ 0.03073	Line 11 plus Line 12
14	$CAD to $US	Ratio	1.0433	Page 27
15	Variable Transportation Rate	$US / GJ	$ 0.0321	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ 0.0339	Line 15 divided by Line 16

Daily currency converter

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

Currency Converter (Using rates from July 14, 2011)

Amount:	1.00 cash rate:
From:	Canadian Dollar
To:	U.S. dollar

Convert

Answer:	1.04
Exchange Rate:	1.0433
Summary:	On 14 July 2011, 1.00 Canadian Dollar(s) = 1.04 U.S. dollar(s), at an exchange rate of 1.0433 (using nominal rate).

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Transportation Tolls
Proposed 2011 Final Annualized Tolls

System Average Unit Cost of Transportation

Line No	Particulars	Net Revenue Requirement ($000's)	Allocation Base		Annual Unit Cost		Daily Unit Cost	
	(a)	(b)	(c)		(d)		(e)	
1	Fixed Energy	83,729	3,972,806	GJ	21.0755941843	$/GJ	0.0577413539	$/GJ
2	Transmission - Fixed	1,284,250	4,713,266,859	GJ-KM	0.2724754900	$/GJ-Km	0.0007465082	$/GJ-Km
3	Transmission - Variable	30,052	1,247,271,838,995	GJ-KM	-	$/GJ-Km	0.0000240941	$/GJ-Km

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
4	Centram MDA	4.98582	0.00374	0.1677
5	Union WDA	35.51965	0.03576	1.2035
6	Union NDA	13.85012	0.01317	0.4685
7	Union EDA	8.99552	0.00781	0.3036
8	KPUC EDA	8.65697	0.00732	0.2919
9	GMIT EDA	15.98156	0.01519	0.5406
10	Enbridge CDA	1.85394	0.00013	0.0611
11	Enbridge EDA	5.42019	0.00393	0.1821
12	Cornwall	12.33584	0.01123	0.4168
13	Philipsburg	16.29309	0.01543	0.5511

Firm Transportation - Short Notice

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
14	Kirkwall to Thorold - CDA	4.31223	0.00253	0.1443
15	Parkway to Goreway - CDA	2.63753	0.00075	0.0875
16	Parkway to Victoria Square #2 CDA	3.52096	0.00168	0.1174

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
17	Emerson - 1 (Viking)	0.07931	0.00000	0.0026
18	Emerson - 2 (Great Lakes)	0.12563	0.00000	0.0041
19	Dawn *(2)	0.04742	0.00000	0.0016
20	Niagara Falls	0.53661	0.00000	0.0176
21	Iroquois	$\boxed{0.86987}$	0.00000	0.0286
22	Chippawa	0.96767	0.00000	0.0318
23	East Hereford	$\boxed{6.38290}$	$\boxed{0.00537}$	0.2152

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.
*(2) Dawn (including Union SWDA, Enbridge SWDA and Dawn Export)

Union Dawn Receipt Point Surcharge

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
24	Union Dawn Receipt Point Surcharge	$\boxed{0.14372}$	0.00000	0.0047

FT, STFT and Interruptible Transportation Tolls
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Line No.		Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) ii (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls except backhauls) iii ($/GJ)
1	(i)	Union Dawn	Empress	61.09578	0.06297	2.0716	2.2788
2	(i)	Union Dawn	Transgas SSDA	51.22445	0.05297	1.7371	1.9108
3	(i)	Union Dawn	Centram SSDA	47.20930	0.04823	1.6003	1.7603
4	(i)	Union Dawn	Centram MDA	41.11130	0.04208	1.3937	1.5331
5	(i)	Union Dawn	Centrat MDA	41.08223	0.04173	1.3923	1.5315
6	(i)	Union Dawn	Union WDA	40.07158	0.04064	1.3580	1.4938
7	(i)	Union Dawn	Nipigon WDA	36.09184	0.03643	1.2230	1.3453
8	(i)	Union Dawn	Union NDA	19.00218	0.01864	0.6433	0.7076
9	(i)	Union Dawn	Calstock NDA	28.58174	0.02847	0.9682	1.0650
10	(i)	Union Dawn	Tunis NDA	22.66902	0.02219	0.7675	0.8443
11	(i)	Union Dawn	GMIT NDA	18.32871	0.01749	0.6201	0.6821
12	(i)	Union Dawn	Union SSMDA	15.57330	0.01466	0.5267	0.5794
13	(i)	Union Dawn	Union NCDA	11.08404	0.00993	0.3743	0.4117
14	(i)	Union Dawn	Union CDA	7.07298	0.00553	0.2380	0.2618
15	(i)	Union Dawn	Enbridge CDA	8.41991	0.00705	0.2839	0.3123
16	(i)	Union Dawn	Union EDA	14.32446	0.01343	0.4843	0.5327
17	(i)	Union Dawn	Enbridge EDA	17.51901	0.01675	0.5928	0.6521
18	(i)	Union Dawn	GMIT EDA	21.24465	0.02074	0.7192	0.7911
19	(i)	Union Dawn	KPUC EDA	13.80857	0.01279	0.4668	0.5135
20	(i)	Union Dawn	North Bay Junction	15.07036	0.01413	0.5096	0.5606
21	(i) (iv)	Union Dawn	Enbridge SWDA	1.75630	0.00000	0.0577	0.0577
22	(i)	Union Dawn	Union SWDA	1.99108	0.00013	0.0656	0.0722
23	(i)	Union Dawn	Spruce	41.08223	0.04173	1.3923	1.5315
24	(i)	Union Dawn	Emerson 1	37.85998	0.03831	1.2830	1.4113
25	(i)	Union Dawn	Emerson 2	37.85998	0.03831	1.2830	1.4113
26	(i)	Union Dawn	St. Clair	2.29739	0.00057	0.0761	0.0837
27	(i) (iv)	Union Dawn	Dawn Export	1.75630	0.00000	0.0577	0.0577
28	(i)	Union Dawn	Kirkwall	6.04030	0.00455	0.2032	0.2235
29	(i)	Union Dawn	Niagara Falls	8.56932	0.00723	0.2889	0.3178
30	(i)	Union Dawn	Chippawa	8.62359	0.00729	0.2908	0.3199
31	(i)	Union Dawn	Iroquois	16.60145	0.01575	0.5616	0.6178
32	(i)	Union Dawn	Cornwall	17.56328	0.01677	0.5942	0.6536
33	(i)	Union Dawn	Napierville	21.05188	0.02047	0.7126	0.7839
34	(i)	Union Dawn	Philipsburg	21.44833	0.02090	0.7261	0.7987
35	(i)	Union Dawn	East Hereford	25.65149	0.02536	0.8687	0.9556
36	(i)	Union Dawn	Welwyn	47.20930	0.04823	1.6003	1.7603
37		Enbridge CDA	Empress	67.48624	0.06975	2.2885	2.5174
38		Enbridge CDA	Transgas SSDA	57.61264	0.05974	1.9538	2.1492
39		Enbridge CDA	Centram SSDA	53.59976	0.05501	1.8172	1.9989
40		Enbridge CDA	Centram MDA	47.49086	0.04885	1.6102	1.7712
41		Enbridge CDA	Centrat MDA	45.53312	0.04644	1.5434	1.6977
42		Enbridge CDA	Union WDA	35.13614	0.03535	1.1906	1.3097
43		Enbridge CDA	Nipigon WDA	30.84011	0.03084	1.0447	1.1492
44		Enbridge CDA	Union NDA	13.75044	0.01304	0.4651	0.5116
45		Enbridge CDA	Calstock NDA	23.33023	0.02287	0.7899	0.8689
46		Enbridge CDA	Tunis NDA	17.41751	0.01660	0.5892	0.6481
47		Enbridge CDA	GMIT NDA	13.07720	0.01190	0.4418	0.4860
48		Enbridge CDA	Union SSMDA	22.23465	0.02171	0.7527	0.8280
49		Enbridge CDA	Union NCDA	5.83253	0.00434	0.1961	0.2157
50		Enbridge CDA	Union CDA	3.84755	0.00201	0.1285	0.1414
51	(iv)	Enbridge CDA	Enbridge CDA	1.75630	0.00000	0.0577	0.0577
52		Enbridge CDA	Union EDA	8.58068	0.00729	0.2894	0.3183
53		Enbridge CDA	Enbridge EDA	11.76682	0.01061	0.3975	0.4373
54		Enbridge CDA	GMIT EDA	15.49951	0.01461	0.5242	0.5766
55		Enbridge CDA	KPUC EDA	8.06547	0.00666	0.2719	0.2991
56		Enbridge CDA	North Bay Junction	9.82112	0.00854	0.3314	0.3645
57		Enbridge CDA	Enbridge SWDA	8.41742	0.00705	0.2838	0.3122
58		Enbridge CDA	Union SWDA	8.65243	0.00718	0.2917	0.3209
59		Enbridge CDA	Spruce	45.53312	0.04644	1.5434	1.6977
60		Enbridge CDA	Emerson 1	44.52178	0.04536	1.5091	1.6600
61		Enbridge CDA	Emerson 2	44.52178	0.04536	1.5091	1.6600
62		Enbridge CDA	St. Clair	8.96078	0.00763	0.3022	0.3324
63		Enbridge CDA	Dawn Export	8.41991	0.00705	0.2839	0.3123
64		Enbridge CDA	Kirkwall	4.13592	0.00251	0.1385	0.1524
65		Enbridge CDA	Niagara Falls	5.65815	0.00416	0.1902	0.2092
66		Enbridge CDA	Chippawa	5.72967	0.00424	0.1926	0.2119
67		Enbridge CDA	Iroquois	10.85834	0.00962	0.3666	0.4033
68		Enbridge CDA	Cornwall	11.82018	0.01064	0.3992	0.4391
69		Enbridge CDA	Napierville	15.30878	0.01434	0.5176	0.5694
70		Enbridge CDA	Philipsburg	15.70523	0.01476	0.5311	0.5842
71		Enbridge CDA	East Hereford	19.90839	0.01922	0.6737	0.7411
72		Enbridge CDA	Welwyn	53.59976	0.05501	1.8172	1.9989
73		Enbridge EDA	Empress	69.69557	0.07210	2.3635	2.5999
74		Enbridge EDA	Transgas SSDA	59.82423	0.06210	2.0289	2.2318
75		Enbridge EDA	Centram SSDA	55.80908	0.05736	1.8922	2.0814
76		Enbridge EDA	Centram MDA	49.73855	0.05124	1.6864	1.8550
77		Enbridge EDA	Centrat MDA	46.95181	0.04796	1.5916	1.7508
78		Enbridge EDA	Union WDA	36.40678	0.03672	1.2336	1.3570

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Proposed 2011 Final Annualized Tolls

Line No.		Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) ii (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls except backhauls) iii ($/GJ)
1		Union Parkway Belt	Centrat MDA	45.78130	0.04672	1.5518	1.7070
2		Union Parkway Belt	Union WDA	35.23627	0.03547	1.1940	1.3134
3		Union Parkway Belt	Nipigon WDA	30.94024	0.03097	1.0482	1.1530
4		Union Parkway Belt	Union NDA	13.85058	0.01317	0.4686	0.5155
5		Union Parkway Belt	Calstock NDA	23.43014	0.02300	0.7933	0.8726
6		Union Parkway Belt	Tunis NDA	17.51742	0.01672	0.5926	0.6519
7		Union Parkway Belt	GMIT NDA	13.17711	0.01203	0.4452	0.4897
8		Union Parkway Belt	Union SSMDA	20.72491	0.02013	0.7015	0.7717
9		Union Parkway Belt	Union NCDA	5.93244	0.00447	0.1995	0.2195
10		Union Parkway Belt	Union CDA	2.27627	0.00028	0.0751	0.0826
11		Union Parkway Belt	Enbridge CDA	3.49424	0.00181	0.1167	0.1284
12		Union Parkway Belt	Union EDA	9.17286	0.00796	0.3096	0.3406
13		Union Parkway Belt	Enbridge EDA	12.36740	0.01128	0.4179	0.4597
14		Union Parkway Belt	GMIT EDA	16.09305	0.01527	0.5444	0.5988
15		Union Parkway Belt	KPUC EDA	8.65697	0.00732	0.2919	0.3211
16		Union Parkway Belt	North Bay Junction	9.91876	0.00866	0.3348	0.3683
17		Union Parkway Belt	Enbridge SWDA	6.90790	0.00547	0.2326	0.2559
18		Union Parkway Belt	Union SWDA	7.14269	0.00560	0.2404	0.2644
19		Union Parkway Belt	Spruce	45.78130	0.04672	1.5518	1.7070
20		Union Parkway Belt	Emerson 1	43.01159	0.04378	1.4579	1.6037
21		Union Parkway Belt	Emerson 2	43.01159	0.04378	1.4579	1.6037
22		Union Parkway Belt	St. Clair	7.44899	0.00604	0.2509	0.2760
23		Union Parkway Belt	Dawn Export	6.90790	0.00547	0.2326	0.2559
24		Union Parkway Belt	Kirkwall	2.62391	0.00092	0.0872	0.0959
25		Union Parkway Belt	Niagara Falls	4.76965	0.00320	0.1600	0.1760
26		Union Parkway Belt	Chippawa	4.82392	0.00326	0.1619	0.1781
27		Union Parkway Belt	Iroquois	11.44984	0.01029	0.3867	0.4254
28		Union Parkway Belt	Cornwall	12.41168	0.01131	0.4194	0.4613
29		Union Parkway Belt	Napierville	15.90028	0.01501	0.5377	0.5915
30		Union Parkway Belt	Philipsburg	16.29673	0.01543	0.5512	0.6063
31		Union Parkway Belt	East Hereford	20.49989	0.01989	0.6939	0.7633
32		Union Parkway Belt	Welwyn	52.36090	0.05370	1.7752	1.9527
33		Union NCDA	Empress	64.36163	0.06640	2.1824	2.4006
34		Union NCDA	Transgas SSDA	54.49052	0.05640	1.8479	2.0327
35		Union NCDA	Centram SSDA	50.47514	0.05166	1.7112	1.8823
36		Union NCDA	Centram MDA	44.40848	0.04555	1.5056	1.6562
37		Union NCDA	Centrat MDA	41.60516	0.04225	1.4101	1.5511
38		Union NCDA	Union WDA	31.06013	0.03101	1.0522	1.1574
39		Union NCDA	Nipigon WDA	26.76410	0.02650	0.9064	0.9970
40		Union NCDA	Union NDA	9.67444	0.00871	0.3268	0.3595
41		Union NCDA	Calstock NDA	19.25399	0.01853	0.6515	0.7167
42		Union NCDA	Tunis NDA	13.34128	0.01226	0.4509	0.4960
43		Union NCDA	GMIT NDA	9.00120	0.00756	0.3035	0.3339
44		Union NCDA	Union SSMDA	24.90105	0.02459	0.8433	0.9276
45	(iv)	Union NCDA	Union NCDA	1.75630	0.00000	0.0577	0.0577
46		Union NCDA	Union CDA	6.45241	0.00474	0.2168	0.2385
47		Union NCDA	Enbridge CDA	5.83253	0.00434	0.1961	0.2157
48		Union NCDA	Union EDA	11.13536	0.01009	0.3762	0.4138
49		Union NCDA	Enbridge EDA	13.36739	0.01235	0.4519	0.4971
50		Union NCDA	GMIT EDA	17.88140	0.01721	0.6051	0.6656
51		Union NCDA	KPUC EDA	10.71825	0.00954	0.3619	0.3981
52		Union NCDA	North Bay Junction	5.74262	0.00420	0.1930	0.2123
53		Union NCDA	Enbridge SWDA	11.08404	0.00993	0.3743	0.4117
54		Union NCDA	Union SWDA	11.31883	0.01006	0.3822	0.4204
55		Union NCDA	Spruce	41.60516	0.04225	1.4101	1.5511
56		Union NCDA	Emerson 1	44.82423	0.04567	1.5194	1.6713
57		Union NCDA	Emerson 2	44.82423	0.04567	1.5194	1.6713
58		Union NCDA	St. Clair	11.62513	0.01051	0.3927	0.4320
59		Union NCDA	Dawn Export	11.08404	0.00993	0.3743	0.4117
60		Union NCDA	Kirkwall	6.80005	0.00539	0.2290	0.2519
61		Union NCDA	Niagara Falls	8.94579	0.00766	0.3018	0.3320
62		Union NCDA	Chippawa	9.00006	0.00772	0.3036	0.3340
63		Union NCDA	Iroquois	13.28769	0.01228	0.4492	0.4941
64		Union NCDA	Cornwall	14.19980	0.01324	0.4800	0.5280
65		Union NCDA	Napierville	17.68840	0.01695	0.5985	0.6584
66		Union NCDA	Philipsburg	18.08485	0.01737	0.6120	0.6732
67		Union NCDA	East Hereford	22.28801	0.02183	0.7546	0.8301
68		Union NCDA	Welwyn	50.47514	0.05166	1.7112	1.8823
69		Union SSMDA	Empress	50.99943	0.05225	1.7290	1.9019
70		Union SSMDA	Transgas SSDA	41.12833	0.04225	1.3945	1.5340
71		Union SSMDA	Centram SSDA	37.11295	0.03752	1.2577	1.3835
72		Union SSMDA	Centram MDA	31.01517	0.03136	1.0511	1.1562
73		Union SSMDA	Centrat MDA	30.98588	0.03102	1.0497	1.1547
74		Union SSMDA	Union WDA	42.41736	0.04323	1.4377	1.5815
75		Union SSMDA	Nipigon WDA	45.82694	0.04676	1.5534	1.7087
76		Union SSMDA	Union NDA	32.81919	0.03330	1.1123	1.2235
77		Union SSMDA	Calstock NDA	42.39874	0.04313	1.4370	1.5807
78		Union SSMDA	Tunis NDA	36.48603	0.03685	1.2364	1.3600

TRANSPORTATION RATES

(A) Applicability

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn – Oakville facilities.

(C) Rates

The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

	Monthly Demand Charge (applied to daily contract demand) Rate/GJ	Commodity and Fuel Changes Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1)				
Dawn to Oakville/Parkway	$\boxed{\$2.332}$	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$1.985			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$2.877	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$5.597	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall - Maximum	$5.597			
Parkway (TCPL) to Parkway (Cons) (2)		0.328%		

Authorized Overrun (3)

Authorized overrun rates will be payable on all quantities in excess of Union's obligation on any day. The overrun charges payable will be calculated at the following rates. Overrun will be authorized at Union's sole discretion.

	If Union supplies fuel Commodity Charge Rate/GJ	Commodity and Fuel Changes Fuel Ratio %	AND	Commodity Charge Rate/GJ
Transportation Overrun				
Dawn to Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.077
Dawn to Kirkwall				$0.065
Parkway to Dawn				$0.077
Parkway (TCPL) Overrun (4)	n/a	0.540%		n/a

uniongas
A Spectra Energy Company

Current M12 Rates and Fuel

Current OEB approved rates effective April 1, 2011

		Contracted Quantity			Authorized Overrun	
Receipt Point	Delivery Point	Daily Demand Charge $CDN/GJ	Month	Fuel %	Daily Variable Charge $CDN/GJ	Fuel %
Dawn	Parkway	$ 0.077	January	1.306%	$ 0.077	1.911%
			February	1.207%		1.812%
			March	1.046%		1.651%
			April	0.763%		1.368%
			May	0.624%		1.228%
			June	0.416%		1.021%
			July	0.357%		0.962%
			August	0.350%		0.955%
			September	0.368%		0.972%
			October	0.745%		1.350%
			November	0.948%		1.553%
			December	1.174%		1.779%
			Summer Avg	**0.518%**		
			Winter Avg	**1.136%**		
Dawn	Kirkwall	$ 0.065	January	1.076%	$ 0.065	1.681%
			February	0.991%		1.596%
			March	0.854%		1.458%
			April	0.763%		1.368%
			May	0.624%		1.228%
			June	0.328%		0.933%
			July	0.328%		0.933%
			August	0.328%		0.933%
			September	0.348%		0.952%
			October	0.697%		1.302%
			November	0.765%		1.370%
			December	0.950%		1.555%
			Summer Avg	**0.488%**		
			Winter Avg	**0.927%**		

Service	Description	Daily Demand Charge $CDN/GJ
F24-T	Firm All Day Transportation	$ 0.02268

Notes:

The above Rate Summary is **not** intended to replace the regulated M12 rate schedule
In the case of a discrepancy between these summaries and the regulated rate schedules, the **rate schedule** will be deemed correct
All services are subject to any applicable taxes

If you have any questions please contact your Account Manager

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 $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.

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/ Maximum	Minimum	Zone 2 2/ 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/ Maximum	Minimum	Zone 2 2/ Maximum	Minimum
Reservation Charge ($ per Dth per month)	$0.8391	0.0000	$5.2182	0.0000
Usage Charge ($ per Dth)	0.0135	0.0000	0.0840	0.0000
ACA Charge	0.0019	0.0019	0.0019	0.0019
Usage and ACA Charge	0.0154	0.0019	0.0859	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.

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 $\boxed{\$0.4623}$/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.

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 TUCHFARSKY

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: $4.5625/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 JULCHINSKY

Title: ANALYST

Telephone: (___) 508-836 7257

Fax: (___) 508-870-2294

Historic TransCanada Fuel Loss Percentages

	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Last 12 Months
Union Parkway Belt - Iroquois	1.18%	1.14%	1.37%	1.09%	1.04%	0.98%	1.06%	1.24%	1.21%	0.88%	1.12%	1.07%	1.12%
Union Dawn - East Hereford	1.08%	1.03%	1.20%	0.98%	0.93%	0.62%	0.83%	1.24%	1.14%	0.60%	1.31%	1.15%	0.97%

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Average
Vector	Alliance	W-10 Storage	0.95%	0.99%	1.40%	1.69%	1.68%	1.51%	1.30%	0.85%	0.65%	0.86%	0.90%	1.01%	1.15%
Vector	Alliance	Dawn	0.95%	0.99%	1.40%	1.69%	1.68%	1.51%	1.30%	0.85%	0.65%	0.86%	0.90%	1.01%	1.15%
Vector	W-10 Stora	Dawn	0.32%	0.33%	0.47%	0.56%	0.56%	0.50%	0.43%	0.28%	0.22%	0.29%	0.30%	0.34%	0.38%

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.

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

Gas Midstream Services

DTE Gas Storage - Washington 10 Historic Fuel Rates

Effective Date	Injection	Withdrawal	Wheel From Hub to Interconnect
Apr 1, 2011	1.10%	0.40%	0.60%
Feb 1, 2011	1.00%	0.50%	0.60%
Nov 1, 2010	1.00%	0.50%	0.30%
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

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EXHIBIT A

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

[redacted]

Date: July 26, 2011

Transaction Confirmation: [redacted]

This Transaction Confirmation is subject to the Base Contract between [redacted] and Northern dated July 26, 2011. The terms of this Transaction Confirmation are binding unless disputed in writing within two (2) Business Days of receipt unless otherwise specified in the Base Contract.

SELLER: [redacted]	**BUYER:** Northern Utilities, Inc. 6 Liberty Lane West Hampton, NH 03842 Attn: Energy Contracts Phone: (603) 773-6430 Fax: (603) 773-6647 Base Contract No.: [redacted]

Contract Price: Buyer shall pay to Seller a Contract Price equal to components (i) Commodity Rate and (ii) Call Payment as follows:

(i) Commodity Rate:

[redacted]

(ii) Call Payment:

[redacted]

(Components (i) Commodity Rate, and (ii) Call Payment referenced herein is hereinafter collectively referred to as the "Contract Price").

Delivery Period: November 1, 2011, through and including October 31, 2012.

Performance Obligation and Contract Quantity: Firm Liquid Service:

[redacted]

Delivery Point(s): For firm delivery service of LNG, at the truck loading flange of Distrigas of Massachusetts LLC's marine LNG terminal located in Everett, Massachusetts.

Special Conditions:

Transportation of LNG from Seller's marine LNG terminal in Everett, Massachusetts shall be scheduled by Buyer. Seller may require Buyer to schedule such deliveries of LNG from Seller's marine LNG terminal any time within a twenty-four (24) hour per day, seven (7) day per week schedule. All costs associated with such transportation, including any surcharges, shall be the responsibility of Buyer. Notwithstanding anything contained in the preceding sentence, upon request by Buyer, Seller shall use commercially reasonable efforts to accommodate Buyer's preferred delivery schedule of its LNG purchases herein.

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

Date: July 25, 2011
Transaction Confirmation # [redacted]

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated August 1, 2004. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:	**BUYER:**
[redacted]	Northern Utilities, Inc. 6 Liberty Lane West Hampton, NH 03842-1720 Attn: Ann Hartigan Phone: (603) 773-6430 Fax: (603) 773-6647 Email: energy_contracts@unitil.com
Base Contract No. ______	Base Contract No. ______
Transporter: ______	Transporter: ______
Transporter Contract Number: ______	Transporter Contract Number: ______

Contract Price: [redacted]

Delivery Period: Begin: December 1, 2011 End: February 29, 2012

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
____ MMBtus/day ☐ EFP	[redacted] MMBtus/day Minimum MMBtus/day Maximum **(see special condition 1)** subject to Section 4.2. at election of ☒ Buyer or ☐ Seller	Up to ______ MMBtus/day

Delivery Point(s): The primary Delivery Point is Dracut, MA. Buyer may also elect secondary deliveries at any point of delivery on the Portland Natural Gas Transmission System, subject to special condition 1 below.

Special Conditions:

[redacted]

[redacted]	Buyer: ______ By: ______ Title: TREASURER Date: 7/25/11

 [redacted]

NAESB Standard 6.3.1

CONFIDENTIAL

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

[redacted]

July 15, 2011
Transaction Confirmation #: ______

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated May 1, 2004. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:	**BUYER:**
[redacted]	Northern Utilities ("NU") 6 Liberty Lane West Hampton, NH 03842-1720 Attn: Ann Hartigan Phone: (603) 773-6430 Fax: (603) 773-6630
Base Contract No. ___________	Base Contract No. ______________________________
Transporter:	Transporter:
Transporter Contract Number:______________________	Transporter Contract Number:____________________

Contract Price: See Special Conditions

Delivery Period: Begin: November 1, 2011 End: March 31, 2012

Performance Obligation and Contract Quantity:
Firm (Variable Quantity): [redacted]

Delivery Point(s): Pleasant Street meter # 020206 on Tennessee Gas Pipeline Company in Zone 6 200 Leg

Special Conditions:

[redacted]

Seller: [redacted]	Buyer: Northern Utilities, Inc.
By: ______________________________	By: ______________________________
Title: ______________________________	Title: TREASURER
Date: ______________________________	Date: 7/15/11

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2011 through October 2012		
Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (3,446,717)	Page 2
NH Division Storage Contract Capacity Assignment	$ (250,798)	Page 3
NH Division Peaking Demand	$ (398,894)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 206,395	Page 5
NH Division Net PNGTS Litigation Costs Assigned to Retail Suppliers	$ (34,007)	Page 6
NH Division Capacity Assignment Demand Revenue	$ (3,924,022)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2011 through October 31, 2012

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	93002F	$ 308,943	$ -	$ -	Y	4,211	-	(346)	-	$ (25,384)
Algonquin	93201A1C	$ 83,632	$ 6,097	$ -	N	NA	NA	-	-	$ -
Granite	10-010-FT-NN	$ 1,094,461	$ 1,321,679	$ 1,303,860	Y	29,421	35,529	(2,419)	(2,912)	$ (332,382)
Iroquois	R181001	$ 520,036	$ -	$ -	Y	6,569	-	(540)	-	$ (42,749)
PNGTS	1997-003	$ 531,242	$ -	$ -	Y	1,100	-	(90)	-	$ (43,465)
PNGTS	1997-004	$ -	$ 12,616,989	$ -	Y	-	33,000	-	(2,705)	$ (1,034,211)
Tennessee	5083	$ 1,828,471	$ -	$ -	Y	4,605	-	(379)	-	$ (150,486)
Tennessee	5083	$ 3,023,386	$ -	$ -	Y	8,550	-	(703)	-	$ (248,590)
Tennessee	5265	$ -	$ 387,384	$ -	Y	-	2,653	-	(217)	$ (31,686)
Tennessee	5292	$ 182,088	$ -	$ -	Y	1,406	-	(116)	-	$ (15,023)
Tennessee	46314	$ 51,263	$ -	$ -	Y	950	-	(78)	-	$ (4,209)
Tennessee	31861	$ 288,284	$ -	$ -	Y	2,226	-	(183)	-	$ (23,700)
Tennessee	39735	$ 120,313	$ -	$ -	Y	929	-	(76)	-	$ (9,843)
Tennessee	41099	$ 552,609	$ -	$ -	Y	4,267	-	(351)	-	$ (45,457)
Texas Eastern	800464	$ 234	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 1,303	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 609	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 7,784	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800384	$ 66,214	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 939	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800436	$ 4,056	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	33322	$ -	$ 14,451,238	$ -	Y	-	34,000	-	(2,787)	$ (1,184,576)
TransCanada	29594	$ 966,126	$ -	$ -	Y	5,937	-	(488)	-	$ (79,412)
Union	M12205	$ 184,916	$ -	$ -	Y	6,003	-	(494)	-	$ (15,217)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	$ -	Y	-	17,172	-	(1,407)	$ (128,389)
Vector	CRL-NUI-0727	$ -	$ 389,774	$ -	Y	-	17,086	-	(1,400)	$ (31,938)
Vector	FT-1-NUI-0122	$ 566,295	$ -	$ -	Y	6,070	-	(499)	-	$ (46,554)
Vector	FT-1-NUI-C0122	$ 36,238	$ -	$ -	Y	6,070	-	(499)	-	$ (2,979)

Total NH Capacity Assignment Credits $ (3,446,717)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 1, 2011 through October 31, 2012

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 169,959	Y	N	(21,256)	(348)	$ (13,930)
W-10	01052	$ 2,890,000	Y	Y	(278,668)	(2,787)	$ (236,868)

Total NH Division Storage Capacity Assignment $ (250,798)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
New Hampshire Division
Peaking Demand Capacity Assignment Revenues
November 1, 2011 through April 30, 2012

Month	Retail Supplier 1	Retail Supplier 2	Retail Supplier 3	Retail Supplier 4	Retail Supplier 5	Retail Supplier 6	Retail Supplier 7	Total Peaking Demand TCQ	Rate	Demand Revenue
Nov-11	1,105	396	219	3,224	-	-	177	5,121	$ 12.98	$ (66,482)
Dec-11	1,105	396	219	3,224	-	-	177	5,121	$ 12.98	$ (66,482)
Jan-12	1,105	396	219	3,224	-	-	177	5,121	$ 12.98	$ (66,482)
Feb-12	1,105	396	219	3,224	-	-	177	5,121	$ 12.98	$ (66,482)
Mar-12	1,105	396	219	3,224	-	-	177	5,121	$ 12.98	$ (66,482)
Apr-12	1,105	396	219	3,224	-	-	177	5,121	$ 12.98	$ (66,482)

Total Division Peaking Demand Revenue $ (398,894)

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2011 through October 2012

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	$ (890,000)	Yes	Pipeline	8.22%	$ 73,184
Wash 10 via Vector, TCPL, PNGTS	$ (1,620,000)	Yes	Storage	8.22%	$ 133,211
Tennessee Niagara	$ (125,000)	No	Pipeline	8.22%	$ -
Tennessee Long-Haul	$ (1,452,000)	No	Pipeline	8.22%	$ -
Total Asset Management	$ (4,087,000)				$ 206,395

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	8.22%	$ -
AGT Contract 93201A1C	$ (98,779)	No	Pipeline	8.22%	$ -
Tennessee 5265	$ (103,375)	No	Pipeline	8.20%	$ -
Granite 10-010-FT-NN	$ (27,675)	No	Pipeline	8.20%	$ -
Granite 10-010-FT-NN	$ (12,160)	No	Pipeline	8.20%	$ -
Granite 10-010-FT-NN	$ (4,800)	No	Pipeline	8.20%	$ -
Total Capacity Release	$ (268,855)				$ -

Total Asset Management and Capacity Release Revenue	$ (4,355,855)	$ 206,395

Northern Utilities, Inc.
New Hampshire Division
PNGTS Litigation Costs Assigned to Retail Suppliers
November 2011 through October 2012

PNGTS Litigation Costs	$ 414,873

PNGTS Contract	MDQ	Percentage MDQ	Allocated PNGTS Litigation Items	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ 13,383	Pipeline	8.22%	$ (1,100)
PNGTS Contract 1997-004	33,000	97%	$ 401,490	Storage	8.20%	$ (32,907)
PNGTS Total	34,100	100%	$ 414,873			$ (34,007)

Northern Utilities, Inc.
Expenses Incurred to Oppose Proposed PNGTS Rate Increases, 8/13/2010 - 7/31/2011

Service Provider	Expense	Maine	New Hampshire
Bates White, LLC - Total	**$ 39,085.00**		
Benjamin Schlesinger - Total	**$ 43,934.07**		
Continental Economics, Inc. - Total	**$ 29,958.15**		
Jeffry L. Fink - Total	**$ 41,330.72**		
Snake Hill - Total	**$ 17,755.39**		
Winstead PC - Total	**$ 706,161.49**		
All Service Providers - Total	**$ 878,224.82**	**$ 463,351.42**	**$ 414,873.40**

Schedule 6A and 6B

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 Supplies							
Chicago	$ 296,323	$ -	$ 97,723	$ 19,270	$ 48,151	$ 416,860	$ 878,328
Lewiston Baseload	$ 987,195	$1,056,929	$ 1,078,071	$1,009,635	$1,073,979	$ 354,300	$ 5,560,110
PNGTS	$ 178,404	$ 191,047	$ 194,891	$ 182,520	$ 194,147	$ 141,234	$ 1,082,241
Niagara	$ -	$ -	$ 25,963	$ -	$ 1,856	$ 27,338	$ 55,157
Tennessee Production	$1,291,664	$1,421,871	$ 614,731	$ 389,112	$1,447,426	$1,599,817	$ 6,764,622
Tenn Zone 4 Spot	$ 241,276	$ 235,303	$ -	$ -	$ 308	$ 285,890	$ 762,777
W10 AMA Spot	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Pipeline	$2,994,861	$2,905,150	$ 2,011,379	$1,600,538	$2,765,867	$2,825,440	$ 15,103,235
Underground Storage							
Tennessee Storage	$ -	$ 55,804	$ 291,711	$ 272,891	$ 289,697	$ -	$ 910,102
Washington 10 Storage	$ 383,444	$2,041,019	$ 3,444,174	$3,154,404	$1,515,997	$ -	$ 10,539,039
Subtotal Storage	$ 383,444	$2,096,823	$ 3,735,885	$3,427,295	$1,805,693	$ -	$ 11,449,141
Peaking Supplies							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 81,501
Subtotal Peaking	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 81,501
Total Commodity Cost	$3,387,026	$5,011,087	$ 5,771,242	$5,037,140	$4,581,342	$2,846,039	$ 26,633,877

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 Supplies							
Chicago	65,773	0	20,052	3,945	9,932	89,219	188,922
Lewiston Baseload	165,000	170,500	170,500	159,500	170,500	75,000	911,000
PNGTS	29,895	30,892	30,892	28,899	30,892	29,895	181,363
Niagara	0	0	5,095	0	366	5,732	11,194
Tennessee Production	301,628	315,471	132,621	83,816	313,893	348,124	1,495,554
Tenn Zone 4 Spot	55,432	51,469	0	0	66	61,377	168,345
W10 AMA Spot	0	0	0	0	0	0	0
Subtotal Pipeline	617,729	568,332	359,160	276,160	525,649	609,348	2,956,378
Underground Storage							
Tennessee Storage	0	12,175	63,645	59,538	63,205	0	198,563
Washington 10 Storage	84,573	450,172	759,655	695,743	334,372	0	2,324,515
Subtotal Storage	84,573	462,347	823,299	755,281	397,577	0	2,523,077
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
LNG	1,350	1,395	3,453	1,305	1,395	3,120	12,018
Subtotal Peaking	1,350	1,395	3,453	1,305	1,395	3,120	12,018
Total Delivered (Dth)	703,652	1,032,074	1,185,912	1,032,746	924,621	612,468	5,491,472

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 Supplies							
Chicago	$ 4.505		$ 4.873	$ 4.884	$ 4.848	$ 4.672	$ 4.649
Lewiston Baseload	$ 5.983	$ 6.199	$ 6.323	$ 6.330	$ 6.299	$ 4.724	$ 6.103
PNGTS	$ 5.968	$ 6.184	$ 6.309	$ 6.316	$ 6.285	$ 4.724	$ 5.967
Niagara			$ 5.095		$ 5.066	$ 4.769	$ 4.927
Tennessee Production	$ 4.282	$ 4.507	$ 4.635	$ 4.642	$ 4.611	$ 4.596	$ 4.523
Tenn Zone 4 Spot	$ 4.353	$ 4.572			$ 4.673	$ 4.658	$ 4.531
W10 AMA Spot							
Subtotal Pipeline	$ 4.848	$ 5.112	$ 5.600	$ 5.796	$ 5.262	$ 4.637	$ 5.109
Underground Storage							
Tennessee Storage		$ 4.584	$ 4.583	$ 4.583	$ 4.583		$ 4.583
Washington 10 Storage	$ 4.534	$ 4.534	$ 4.534	$ 4.534	$ 4.534		$ 4.534
Subtotal Storage	$ 4.534	$ 4.535	$ 4.538	$ 4.538	$ 4.542		$ 4.538
Peaking Supplies							
Peaking Supply 1							
Peaking Supply 2							
Peaking Supply 3							
LNG	$ 6.460	$ 6.533	$ 6.945	$ 7.132	$ 7.011	$ 6.602	$ 6.782
Subtotal Peaking	$ 6.460	$ 6.533	$ 6.945	$ 7.132	$ 7.011	$ 6.602	$ 6.782
Total Cost per Dth	$ 4.813	$ 4.855	$ 4.867	$ 4.877	$ 4.955	$ 4.647	$ 4.850

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	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	68,967	-	21,076	4,150	10,439	93,639	198,270
2	City Gate Delivered Volume	Sum Lines 64, 84 and 104	65,773	-	20,052	3,945	9,932	89,219	188,922
3	Total Purchase Cost	Line 14	$ 293,249	$ -	$ 96,779	$ 19,084	$ 47,684	$ 412,667	$ 869,463
4	Variable Transportation Costs	Sum Lines 26, 46, 56, 66, 76, 86, 96 and 106	$ 3,074	$ -	$ 944	$ 186	$ 467	$ 4,193	$ 8,865
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 296,323	$ -	$ 97,723	$ 19,270	$ 48,151	$ 416,860	$ 878,328
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.505		$ 4.873	$ 4.884	$ 4.848	$ 4.672	$ 4.649
7									
8	Chicago Supply Costs								
9	Purchased Volumes	Sendout Optimization	68,967	-	21,076	4,150	10,439	93,639	198,270
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.245
11	NYMEX Cost	Line 9 times Line 10	$ 278,835	$ -	$ 92,374	$ 18,217	$ 45,502	$ 406,768	$ 841,696
12	NYMEX Basis Price	Att to Sch 5A, Line 1 of Page 1	$ 0.209		$ 0.209	$ 0.209	$ 0.209	$ 0.063	$ 0.140
13	NYMEX Basis Costs	Line 9 times Line 12	$ 14,414	$ -	$ 4,405	$ 867	$ 2,182	$ 5,899	$ 27,767
14	Total Purchase Price	Line 10 plus Line 12	$ 4.252		$ 4.592	$ 4.599	$ 4.568	$ 4.407	$ 4.385
15	Total Purchase Cost	Line 11 plus Line 13	$ 293,249	$ -	$ 96,779	$ 19,084	$ 47,684	$ 412,667	$ 869,463
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with Union)								
22	Received Volume	Line 9	68,967	-	21,076	4,150	10,439	93,639	198,270
23	Fuel Loss Rate	Att to Sch 5A, Line 68 of Page 2	1.15%		1.15%	1.15%	1.15%	1.15%	1.15%
24	Delivered Volume	Line 22 times (1 - Line 23)	68,174	-	20,833	4,102	10,319	92,562	195,990
25	Variable Transportation Rate	Att to Sch 5A, Line 46 of Page 2	$ 0.0019		$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	$ 130	$ -	$ 40	$ 8	$ 20	$ 176	$ 372
27									
28	Transportation Segment 3								
29	Union Pipeline (Contract M12205)								
30	Receipt Point: Dawn								
31	Delivery Point: Parkway (Interconnects with TransCanada)								
32	Received Volume	Line 14	68,174	-	20,833	4,102	10,319	92,562	195,990
33	Fuel Loss Rate	Att to Sch 5A, Line 66 of Page 2	1.14%		1.14%	1.14%	1.14%	1.14%	1.14%
34	Delivered Volume	Line 32 times (1 - Line 33)	67,397	-	20,596	4,055	10,201	91,507	193,756
35	Variable Transportation Rate	Att to Sch 5A, Line 44 of Page 2	$ -		$ -	$ -	$ -	$ -	$ -
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37									
38	Transportation Segment 4								
39	TransCanada Pipeline (Contract 41235)								
40	Receipt Point: Parkway								
41	Delivery Point: Iroquois								
42	Received Volume	Line 24	67,397	-	20,596	4,055	10,201	91,507	193,756
43	Fuel Loss Rate	Att to Sch 5A, Line 65 of Page 2	1.12%		1.12%	1.12%	1.12%	1.12%	1.12%
44	Delivered Volume	Line 42 times (1 - Line 43)	66,642	-	20,365	4,010	10,087	90,482	191,586
45	Variable Transportation Rate	Att to Sch 5A, Line 43 of Page 2	$ 0.0113		$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113
46	Variable Transportation Costs	Line 44 times Line 45	$ 753	$ -	$ 230	$ 45	$ 114	$ 1,022	$ 2,165
47									
48	Transportation Segment 5								
49	Iroquois Pipeline (Contract R181001)								
50	Receipt Point: Waddington								
51	Delivery Point: Wright (Interconnection with Tennessee)								
52	Received Volume	Line 44	66,642	-	20,365	4,010	10,087	90,482	191,586
53	Fuel Loss Rate	Att to Sch 5A, Line 51 of Page 2	0.21%		0.21%	0.21%	0.21%	0.21%	0.21%
54	Delivered Volume	Line 52 times (1 - Line 53)	66,502	-	20,322	4,001	10,066	90,292	191,183
55	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2	$ 0.0052		$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052
56	Variable Transportation Costs	Line 54 times Line 55	$ 346	$ -	$ 106	$ 21	$ 52	$ 470	$ 994
57									
58	Transporation Segment 6A								
59	Tennessee Gas Pipeline (Contract 31861)								
60	Receipt Point: Mendon								
61	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
62	Received Volume	Line 54	28,729	-	6,487	1,081	3,244	28,846	68,387
63	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2	0.77%		0.77%	0.77%	0.77%	0.77%	0.77%
64	City Gate Delivered Volume	Line 62 times (1 - Line 63)	28,508	-	6,437	1,073	3,219	28,624	67,860
65	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2	$ 0.0269		$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269
66	Variable Transportation Costs	Line 64 times Line 65	$ 767	$ -	$ 173	$ 29	$ 87	$ 770	$ 1,825
67									
68	Transportation Segment 6B								
69	Tennessee Gas Pipeline (Contract 31861)								
70	Receipt Point: Mendon								
71	Delivery Point: Pleasant St. (Interconnection with Granite)								
72	Received Volume	Line 54	14,498	-	3,962	660	1,981	16,733	37,833
73	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2	0.77%		0.77%	0.77%	0.77%	0.77%	0.77%
74	Delivered Volume	Line 72 times (1 - Line 73)	14,386	-	3,931	655	1,966	16,604	37,542
75	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2	$ 0.0269		$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269
76	Variable Transportation Costs	Line 74 times Line 75	$ 387	$ -	$ 106	$ 18	$ 53	$ 447	$ 1,010
77									
78	Transportation Segment 7B								
79	Granite State Gas Transmission (Contract 10-010-FT-NN)								
80	Receipt Point: Pleasant St.								
81	Delivery Point: Northern City Gates								
82	Received Volume	Line 74	14,386	-	3,931	655	1,966	16,604	37,542
83	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
84	City Gate Delivered Volume	Line 82 times (1 - Line 83)	14,336	-	3,917	653	1,959	16,546	37,410
85	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
86	Variable Transportation Costs	Line 84 times Line 85	$ 27	$ -	$ 7	$ 1	$ 4	$ 31	$ 71
87									
88	Transportation Segment 6C								
89	Tennessee Gas Pipeline (Contract 41099)								
90	Receipt Point: Wright								
91	Delivery Point: Mendon (Interconnection with Algonquin)								
92	Received Volume	Line 54	23,276	-	9,874	2,260	4,841	44,713	84,963
93	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2	0.77%		0.77%	0.77%	0.77%	0.77%	0.77%
94	Delivered Volume	Line 92 times (1 - Line 93)	23,096	-	9,798	2,242	4,804	44,369	84,309
95	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2	$ 0.0269		$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269	$ 0.0269
96	Variable Transportation Costs	Line 94 times Line 95	$ 621	$ -	$ 264	$ 60	$ 129	$ 1,194	$ 2,268
97									
98	Transportation Segment 7C								
99	Algonquin Gas Transmission (Contract 93200F)								
100	Receipt Point: Mendon								
101	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
102	Received Volume	Line 94	23,096	-	9,798	2,242	4,804	44,369	84,309
103	Fuel Loss Rate	Att to Sch 5A, Line 48 of Page 2	0.72%		1.02%	1.02%	1.02%	0.72%	0.78%
104	City Gate Delivered Volume	Line 102 times (1 - Line 103)	22,930	-	9,698	2,220	4,755	44,049	83,651
105	Variable Transportation Rate	Att to Sch 5A, Line 25 of Page 2	$ 0.0019		$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
106	Variable Transportation Costs	Line 104 times Line 105	$ 44	$ -	$ 18	$ 4	$ 9	$ 84	$ 159

Source of Supply: Lewiston, ME City-Gate (Maritimes)
City-Gate Delivered Supply

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	165,000	170,500	170,500	159,500	170,500	75,000	911,000
2	City Gate Delivered Volume	Line 1	165,000	170,500	170,500	159,500	170,500	75,000	911,000
3	Total Purchase Cost	Line 14	$ 987,195	$ 1,056,929	$ 1,078,071	$ 1,009,635	$ 1,073,979	$ 354,300	$ 5,560,110
4	Variable Transportation Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 987,195	$ 1,056,929	$ 1,078,071	$ 1,009,635	$ 1,073,979	$ 354,300	$ 5,560,110
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.983	$ 6.199	$ 6.323	$ 6.330	$ 6.299	$ 4.724	$ 6.103
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	165,000	170,500	170,500	159,500	170,500	75,000	911,000
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.292
11	NYMEX Cost	Line 9 times Line 10	$ 667,095	$ 726,160	$ 747,302	$ 700,205	$ 743,210	$ 325,800	$ 3,909,771
12	NYMEX Basis Price	Att to Sch 5A, Line 3 of Page 1	$ 1.940	$ 1.940	$ 1.940	$ 1.940	$ 1.940	$ 0.380	$ 1.812
13	NYMEX Basis Costs	Line 9 times Line 12	$ 320,100	$ 330,770	$ 330,770	$ 309,430	$ 330,770	$ 28,500	$ 1,650,340
14	Total Purchase Price	Line 10 plus Line 12	$ 5.983	$ 6.199	$ 6.323	$ 6.330	$ 6.299	$ 4.724	$ 6.103
15	Total Purchase Cost	Line 11 plus Line 13	$ 987,195	$ 1,056,929	$ 1,078,071	$ 1,009,635	$ 1,073,979	$ 354,300	$ 5,560,110

Source of Supply: PNGTS (Westbrook, ME)
Delivered to Northern via PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	30,000	31,000	31,000	29,000	31,000	30,000	182,000
2	City Gate Delivered Volume	Line 34	29,895	30,892	30,892	28,899	30,892	29,895	181,363
3	Total Purchase Cost	Line 14	$ 178,290	$ 190,929	$ 194,773	$ 182,410	$ 194,029	$ 141,120	$ 1,081,551
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 114	$ 118	$ 118	$ 110	$ 118	$ 114	$ 690
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 178,404	$ 191,047	$ 194,891	$ 182,520	$ 194,147	$ 141,234	$ 1,082,241
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.968	$ 6.184	$ 6.309	$ 6.316	$ 6.285	$ 4.724	$ 5.967
7									
8	Portland Supply Costs								
9	Purchased Volumes	Sendout Optimization	30,000	31,000	31,000	29,000	31,000	30,000	182,000
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.296
11	NYMEX Cost	Line 9 times Line 10	$ 121,290	$ 132,029	$ 135,873	$ 127,310	$ 135,129	$ 130,320	$ 781,951
12	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1	$ 1.900	$ 1.900	$ 1.900	$ 1.900	$ 1.900	$ 0.360	$ 1.646
13	NYMEX Basis Costs	Line 9 times Line 12	$ 57,000	$ 58,900	$ 58,900	$ 55,100	$ 58,900	$ 10,800	$ 299,600
14	Total Purchase Price	Line 10 plus Line 12	$ 5.943	$ 6.159	$ 6.283	$ 6.290	$ 6.259	$ 4.704	$ 5.943
15	Total Purchase Cost	Line 11 plus Line 13	$ 178,290	$ 190,929	$ 194,773	$ 182,410	$ 194,029	$ 141,120	$ 1,081,551
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	PNGTS (Contract 1997-003)								
20	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
21	Delivery Point: Granite (Westbrook)								
22	Received Volume	Line 9	30,000	31,000	31,000	29,000	31,000	30,000	182,000
23	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	30,000	31,000	31,000	29,000	31,000	30,000	182,000
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	$ 57	$ 59	$ 59	$ 55	$ 59	$ 57	$ 346
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	30,000	31,000	31,000	29,000	31,000	30,000	182,000
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	29,895	30,892	30,892	28,899	30,892	29,895	181,363
35	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
36	Variable Transportation Costs	Line 34 times Line 35	$ 57	$ 59	$ 59	$ 55	$ 59	$ 57	$ 345

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	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	-	-	5,140	-	369	5,782	11,291
2	City Gate Delivered Volume	Sum Lines 24, 54 and 44	-	-	5,095	-	366	5,732	11,194
3	Total Purchase Cost	Line 14	$ -	$ -	$ 25,823	$ -	$ 1,846	$ 27,181	$ 54,850
4	Variable Transportation Costs	Sum Lines 26, 56, 36 and 46	$ -	$ -	$ 140	$ -	$ 10	$ 157	$ 307
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ 25,963	$ -	$ 1,856	$ 27,338	$ 55,157
6	Average Delivered Price	Line 5 divided by Line 2			$ 5.095		$ 5.066	$ 4.769	$ 4.927
7									
8	<u>Niagara Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	5,140	-	369	5,782	11,291
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.362
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ 22,528	$ -	$ 1,609	$ 25,117	$ 49,254
12	NYMEX Basis Price	Att to Sch 5A, Line 4 of Page 1			$ 0.641		$ 0.641	$ 0.357	$ 0.496
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ 3,295	$ -	$ 237	$ 2,064	$ 5,595
14	Total Purchase Price	Line 10 plus Line 12			$ 5.024		$ 5.000	$ 4.701	$ 4.858
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ 25,823	$ -	$ 1,846	$ 27,181	$ 54,850
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1A								
19	Tennessee Gas Pipeline (Contract 5292)								
20	Receipt Point: Niagara								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 9	-	-	2,200	-	369	4,317	6,886
23	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2			0.77%		0.77%	0.77%	0.77%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	2,183	-	366	4,284	6,833
25	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2			$ 0.0269		$ 0.0269	$ 0.0269	$ 0.0269
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ 59	$ -	$ 10	$ 115	$ 184
27									
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 39375)								
30	Receipt Point: Niagara								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 9	-	-	1,454	-	-	1,465	2,918
33	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2			0.77%			0.77%	0.77%
34	Delivered Volume	Line 32 times (1 - Line 33)	-	-	1,442	-	-	1,453	2,896
35	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2			$ 0.0269			$ 0.0269	$ 0.0269
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ 39	$ -	$ -	$ 39	$ 78
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	-	-	1,442	-	-	1,453	2,896
43	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	-	-	1,437	-	-	1,448	2,886
45	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ 3	$ -	$ -	$ 3	$ 5
47									
48	Transportation Segment 1C								
49	Tennessee Gas Pipeline (Contract 46314)								
50	Receipt Point: Niagara								
51	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
52	Received Volume	Line 9	-	-	1,486	-	-	-	1,486
53	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2			0.77%				0.77%
54	City Gate Delivered Volume	Line 52 times (1 - Line 53)	-	-	1,475	-	-	-	1,475
55	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2			$ 0.0269				$ 0.0269
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ 40	$ -	$ -	$ -	$ 40

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

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	City Gate Volumes - Z0	Line 2 of Page 6	106,870	110,433	70,669	45,958	110,433	126,350	570,714
2	City Gate Volumes - Z1	Line 2 of Page 7	194,758	205,038	61,952	37,858	203,460	221,774	924,840
3	Total City Gate Volumes	Line 1 plus Line 2	301,628	315,471	132,621	83,816	313,893	348,124	1,495,554
4	City Gate Delivered Costs - Z0	Line 6 of Page 6	$ 457,167	$ 497,317	$ 327,400	$ 213,252	$ 508,850	$ 580,215	$ 2,584,200
5	City Gate Delivered Costs - Z1	Line 6 of Page 7	$ 834,497	$ 924,554	$ 287,331	$ 175,861	$ 938,576	$ 1,019,603	$ 4,180,422
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 1,291,664	$ 1,421,871	$ 614,731	$ 389,112	$ 1,447,426	$ 1,599,817	$ 6,764,622
7	Average Delivered Price	Line 6 divided by Line 3	$ 4.282	$ 4.507	$ 4.635	$ 4.642	$ 4.611	$ 4.596	$ 4.523

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B

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

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 32	111,610	115,330	73,803	47,996	115,330	131,953	596,023
2	City Gate Delivered Volume	Line 44	106,870	110,433	70,669	45,958	110,433	126,350	570,714
3	Total Purchase Price	Line 24	$ 3.964	$ 4.180	$ 4.304	$ 4.311	$ 4.280	$ 4.265	$ 4.204
4	Total Purchase Cost	Line 2 times Line 3	$ 442,421	$ 482,080	$ 317,649	$ 206,911	$ 493,613	$ 562,781	$ 2,505,455
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 14,746	$ 15,237	$ 9,751	$ 6,341	$ 15,237	$ 17,433	$ 78,745
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 457,167	$ 497,317	$ 327,400	$ 213,252	$ 508,850	$ 580,215	$ 2,584,200
7	Average Delivered Price	Line 6 divided by Line 2	$ 4.278	$ 4.503	$ 4.633	$ 4.640	$ 4.608	$ 4.592	$ 4.528
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	-	-
11	Storage Delivered Volume	Line 54	-	-	-	-	-	-	-
12	Total Purchase Price	Line 24	$ 3.964	$ 4.180	$ 4.304	$ 4.311	$ 4.280	$ 4.265	$ 4.204
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Average Delivered Price	Line 15 divided by Line 11							
17									
18	Tennessee Zone 0 Supply Costs								
19	Purchased Volumes	Sendout Optimization	111,610	115,330	73,803	47,996	115,330	131,953	596,023
20	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.283
21	NYMEX Cost	Line 25 times Line 26	$ 451,238	$ 491,191	$ 323,480	$ 210,702	$ 502,724	$ 573,206	$ 2,552,541
22	NYMEX Basis Price	Att to Sch 5A, Line 5 of Page 1							
23	NYMEX Basis Costs	Line 25 times Line 28							
24	Total Purchase Price	Line 26 plus Line 28	$ 3.964	$ 4.180	$ 4.304	$ 4.311	$ 4.280	$ 4.265	$ 4.204
25	Total Purchase Cost	Line 27 plus Line 29	$ 442,421	$ 482,080	$ 317,649	$ 206,911	$ 493,613	$ 562,781	$ 2,505,455
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1A								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone 0								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	111,610	115,330	73,803	47,996	115,330	131,953	596,023
33	Fuel Loss Rate	Att to Sch 5A, Line 54 of Page 2	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%
34	Delivered Volume	Line 32 times (1 - Line 33)	107,246	110,821	70,918	46,119	110,821	126,794	572,718
35	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2	$ 0.1356	$ 0.1356	$ 0.1356	$ 0.1356	$ 0.1356	$ 0.1356	$ 0.1356
36	Variable Transportation Costs	Line 34 times Line 35	$ 14,543	$ 15,027	$ 9,616	$ 6,254	$ 15,027	$ 17,193	$ 77,661
37									
38	Transportation Segment 2A								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	107,246	110,821	70,918	46,119	110,821	126,794	572,718
43	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	106,870	110,433	70,669	45,958	110,433	126,350	570,714
45	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 203	$ 210	$ 134	$ 87	$ 210	$ 240	$ 1,084
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 31 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 32	202,321	213,000	64,357	39,328	211,361	230,386	960,754
2	City Gate Delivered Volume	Line 44	194,758	205,038	61,952	37,858	203,460	221,774	924,840
3	Total Purchase Price	Line 24	$ 4.009	$ 4.225	$ 4.349	$ 4.356	$ 4.325	$ 4.310	$ 4.236
4	Total Purchase Cost	Line 2 times Line 3	$ 811,104	$ 899,926	$ 279,890	$ 171,313	$ 914,138	$ 992,965	$ 4,069,336
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 23,393	$ 24,628	$ 7,441	$ 4,547	$ 24,438	$ 26,638	$ 111,086
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 834,497	$ 924,554	$ 287,331	$ 175,861	$ 938,576	$ 1,019,603	$ 4,180,422
7	Average Delivered Price	Line 6 divided by Line 2	$ 4.285	$ 4.509	$ 4.638	$ 4.645	$ 4.613	$ 4.597	$ 4.520
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	-	-
11	Storage Delivered Volume	Line 54	-	-	-	-	-	-	-
12	Total Purchase Price	Line 24	$ 4.009	$ 4.225	$ 4.349	$ 4.356	$ 4.325	$ 4.310	$ 4.236
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Average Delivered Price	Line 15 divided by Line 11							
17									
18	<u>Tennessee Zone L Supply Costs</u>								
19	Purchased Volumes	Sendout Optimization	202,321	213,000	64,357	39,328	211,361	230,386	960,754
20	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.270
21	NYMEX Cost	Line 25 times Line 26	$ 817,983	$ 907,168	$ 282,078	$ 172,651	$ 921,324	$ 1,000,798	$ 4,102,002
22	NYMEX Basis Price	Att to Sch 5A, Line 6 of Page 1							
23	NYMEX Basis Costs	Line 25 times Line 28							
24	Total Purchase Price	Line 26 plus Line 28	$ 4.009	$ 4.225	$ 4.349	$ 4.356	$ 4.325	$ 4.310	$ 4.236
25	Total Purchase Cost	Line 27 plus Line 29	$ 811,104	$ 899,926	$ 279,890	$ 171,313	$ 914,138	$ 992,965	$ 4,069,336
26									
27	<u>Transportation Fuel Losses and Variable Charges</u>								
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone L								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	202,321	213,000	64,357	39,328	211,361	230,386	960,754
33	Fuel Loss Rate	Att to Sch 5A, Line 56 of Page 2	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
34	Delivered Volume	Line 32 times (1 - Line 33)	195,442	205,758	62,169	37,991	204,175	222,553	928,088
35	Variable Transportation Rate	Att to Sch 5A, Line 34 of Page 2	$ 0.1178	$ 0.1178	$ 0.1178	$ 0.1178	$ 0.1178	$ 0.1178	$ 0.1178
36	Variable Transportation Costs	Line 34 times Line 35	$ 23,023	$ 24,238	$ 7,324	$ 4,475	$ 24,052	$ 26,217	$ 109,329
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	195,442	205,758	62,169	37,991	204,175	222,553	928,088
43	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	194,758	205,038	61,952	37,858	203,460	221,774	924,840
45	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 370	$ 390	$ 118	$ 72	$ 387	$ 421	$ 1,757
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone L								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 55 of Page 2				5.06%			
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 33 of Page 2				$ 0.1033			
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Gross Withdrawn Volume	Line 9	-	12,349	64,554	60,389	64,108	-	201,401
2	City Gate Delivered Volume	Line 36	-	12,175	63,645	59,538	63,205	-	198,563
3	Total Withdrawal Costs	Line 17	$ -	$ 55,331	$ 289,240	$ 270,579	$ 287,242	$ -	$ 902,392
4	Variable Transportation Costs	Sum Lines 28 and 38	$ -	$ 473	$ 2,471	$ 2,312	$ 2,454	$ -	$ 7,710
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ 55,804	$ 291,711	$ 272,891	$ 289,697	$ -	$ 910,102
6	Average Delivered Price	Line 5 divided by Line 2		$ 4.584	$ 4.583	$ 4.583	$ 4.583		$ 4.583
7									
8	<u>Tennessee FS-MA Withdrawn Inventory (Segment 1)</u>								
9	Gross Withdrawn Volume	Sendout Optimization	-	12,349	64,554	60,389	64,108	-	201,401
10	Withdrawal Rate	Att to Sch 5A, Line 1 of Page 3		$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204		$ 0.0204
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ 252	$ 1,317	$ 1,232	$ 1,308	$ -	$ 4,109
12	Inventory Rate	Sch 14, Page 1		$ 4.4602	$ 4.4602	$ 4.4602	$ 4.4602		$ 4.4602
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ 55,079	$ 287,923	$ 269,347	$ 285,934	$ -	$ 898,283
14	Withdrawal Fuel Loss Rate	Att to Sch 5A, Line 1 of Page 3		0.00%	0.00%	0.00%	0.00%		0.00%
15	Withdrawal Fuel Losses	Line 9 times Line 14	-	-	-	-	-	-	-
16	Net Withdrawn Volume	Line 9 minus Line 15	-	12,349	64,554	60,389	64,108	-	201,401
17	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ 55,331	$ 289,240	$ 270,579	$ 287,242	$ -	$ 902,392
18									
19	<u>Transportation Fuel Losses and Variable Charges</u>								
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	-	12,349	64,554	60,389	64,108	-	201,400
25	Fuel Loss Rate	Att to Sch 5A, Line 57 of Page 2		1.06%	1.06%	1.06%	1.06%		1.06%
26	Delivered Volume	Line 24 times (1 - Line 25)	-	12,218	63,870	59,749	63,429	-	199,266
27	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2		$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368		$ 0.0368
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ 450	$ 2,350	$ 2,199	$ 2,334	$ -	$ 7,333
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	-	12,218	63,870	59,749	63,429	-	199,266
35	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
36	City Gate Delivered Volume	Line 34 times (1 - Line 35)	-	12,175	63,645	59,538	63,205	-	198,563
37	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
38	Variable Transportation Costs	Line 36 times Line 37	$ -	$ 23	$ 121	$ 113	$ 120	$ -	$ 377

Source of Supply: Tennessee Zone 4
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	56,225	52,205	-	-	67	62,254	170,751
2	City Gate Delivered Volume	Sum Lines 24, 0 and 0	55,432	51,469	-	-	66	61,377	168,345
3	Total Purchase Cost	Line 14	$ 239,123	$ 233,305	$ -	$ -	$ 306	$ 283,506	$ 756,240
4	Variable Transportation Costs	Sum Lines 26, 0, 36 and 0	$ 2,152	$ 1,999	$ -	$ -	$ 3	$ 2,383	$ 6,537
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 241,276	$ 235,303	$ -	$ -	$ 308	$ 285,890	$ 762,777
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.353	$ 4.572			$ 4.673	$ 4.658	$ 4.531
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	56,225	52,205	-	-	67	62,254	170,751
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.219
11	NYMEX Cost	Line 9 times Line 10	$ 227,316	$ 222,341	$ -	$ -	$ 291	$ 270,433	$ 720,382
12	NYMEX Basis Price	Att to Sch 5A, Line 7 of Page 1	$ 0.210	$ 0.210			$ 0.210	$ 0.210	$ 0.210
13	NYMEX Basis Costs	Line 9 times Line 12	$ 11,807	$ 10,963	$ -	$ -	$ 14	$ 13,073	$ 35,858
14	Total Purchase Price	Line 10 plus Line 12	$ 4.253	$ 4.469			$ 4.569	$ 4.554	$ 4.429
15	Total Purchase Cost	Line 11 plus Line 13	$ 239,123	$ 233,305	$ -	$ -	$ 306	$ 283,506	$ 756,240
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5265)								
20	Receipt Point: Tennessee FS-MA Withdrawal Meter								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	56,225	52,205	-	-	67	62,254	170,751
23	Fuel Loss Rate	Att to Sch 5A, Line 57 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
24	Delivered Volume	Line 22 times (1 - Line 23)	55,629	51,652	-	-	66	61,594	168,941
25	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368	$ 0.0368
26	Variable Transportation Costs	Line 24 times Line 25	$ 2,047	$ 1,901	$ -	$ -	$ 2	$ 2,267	$ 6,217
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	55,629	51,652	-	-	66	61,594	168,941
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	55,432	51,469	-	-	66	61,377	168,345
35	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
36	Variable Transportation Costs	Line 34 times Line 35	$ 105	$ 98	$ -	$ -	$ 0	$ 117	$ 320

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

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Gross Withdrawn Volume	Line 9	86,461	460,219	776,610	711,271	341,835	-	2,376,396
2	City Gate Delivered Volume	Line 66	84,573	450,172	759,655	695,743	334,372	-	2,324,515
3	Total Withdrawal Costs	Line 17	$ 380,082	$ 2,023,124	$ 3,413,977	$ 3,126,748	$ 1,502,705	$ -	$ 10,446,637
4	Variable Transportation Costs	Sum Lines 28, 38, 48, 58 and 68	$ 3,362	$ 17,895	$ 30,197	$ 27,657	$ 13,292	$ -	$ 92,402
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 383,444	$ 2,041,019	$ 3,444,174	$ 3,154,404	$ 1,515,997	$ -	$ 10,539,039
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.534	$ 4.534	$ 4.534	$ 4.534	$ 4.534		$ 4.534
7									
8	<u>Washington 10 Withdrawn Inventory (Segment 1)</u>								
9	Gross Withdrawn Volume	Sendout Optimization	86,461	460,219	776,610	711,271	341,835	-	2,376,396
10	Withdrawal Rate	Att to Sch 5A, Line 4 of Page 3	$ -	$ -	$ -	$ -	$ -		$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	Sch 14	$ 4.3960	$ 4.3960	$ 4.3960	$ 4.3960	$ 4.3960		$ 4.3960
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 380,082	$ 2,023,124	$ 3,413,977	$ 3,126,748	$ 1,502,705	$ -	$ 10,446,637
14	Withdrawal Fuel Loss Rate	Att to Sch 5A, Line 4 of Page 3	0.50%	0.50%	0.50%	0.50%	0.50%		0.50%
15	Withdrawal Fuel Losses	Line 9 times Line 14	432	2,301	3,883	3,556	1,709	-	11,882
16	Net Withdrawn Volume	Line 9 minus Line 15	86,029	457,918	772,727	707,715	340,125	-	2,364,514
17	Total Withdrawal Costs	Line 11 plus Line 13	$ 380,082	$ 2,023,124	$ 3,413,977	$ 3,126,748	$ 1,502,705	$ -	$ 10,446,637
18									
19	<u>Transportation Fuel Losses and Variable Charges</u>								
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	52,034	197,678	383,241	354,043	137,743	-	1,124,739
25	Fuel Loss Rate	Att to Sch 5A, Line 69 of Page 2	0.38%	0.38%	0.38%	0.38%	0.38%		0.38%
26	Delivered Volume	Line 24 times (1 - Line 25)	51,837	196,926	381,785	352,698	137,220	-	1,120,465
27	Variable Transportation Rate	Att to Sch 5A, Line 47 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		$ 0.0019
28	Variable Transportation Costs	Line 26 times Line 27	$ 98	$ 374	$ 725	$ 670	$ 261	$ -	$ 2,129
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	33,994	260,241	389,485	353,672	202,382	-	1,239,775
35	Fuel Loss Rate	Att to Sch 5A, Line 69 of Page 2	0.38%	0.38%	0.38%	0.38%	0.38%		0.38%
36	Delivered Volume	Line 34 times (1 - Line 35)	33,865	259,252	388,005	352,328	201,613	-	1,235,063
37	Variable Transportation Rate	Att to Sch 5A, Line 47 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		$ 0.0019
38	Variable Transportation Costs	Line 36 times Line 37	$ 64	$ 493	$ 737	$ 669	$ 383	$ -	$ 2,347
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	85,702	456,178	769,790	705,026	338,833	-	2,355,529
45	Fuel Loss Rate	Att to Sch 5A, Line 64 of Page 2	0.97%	0.97%	0.97%	0.97%	0.97%		0.97%
46	Delivered Volume	Line 44 times (1 - Line 45)	84,870	451,753	762,323	698,187	335,546	-	2,332,680
47	Variable Transportation Rate	Att to Sch 5A, Line 42 of Page 2	$ 0.0339	$ 0.0339	$ 0.0339	$ 0.0339	$ 0.0339		$ 0.0339
48	Variable Transportation Costs	Line 46 times Line 47	$ 2,877	$ 15,314	$ 25,843	$ 23,669	$ 11,375	$ -	$ 79,078
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	84,870	451,753	762,323	698,187	335,546	-	2,332,679
55	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
56	Delivered Volume	Line 54 times (1 - Line 55)	84,870	451,753	762,323	698,187	335,546	-	2,332,679
57	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019		$ 0.0019
58	Variable Transportation Costs	Line 56 times Line 57	$ 161	$ 858	$ 1,448	$ 1,327	$ 638	$ -	$ 4,432
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	84,870	451,753	762,323	698,187	335,546	-	2,332,679
65	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
66	City Gate Delivered Volume	Line 64 times (1 - Line 65)	84,573	450,172	759,655	695,743	334,372	-	2,324,515
67	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
68	Variable Transportation Costs	Line 66 times Line 67	$ 161	$ 855	$ 1,443	$ 1,322	$ 635	$ -	$ 4,417

Source of Supply: W10 AMA Supplier
Delivered to Northern via PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 34	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 26 and 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 13 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	PNGTS (Contract 1997-004)								
19	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
20	Delivery Point: Granite (Westbrook, Newington, Eliot)								
21	Delivery Point: Granite (Westbrook)								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Peaking Supply 1
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 1 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 8 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 2 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 9 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Peaking Supply 3
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 3 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 10 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Gross Withdrawn Volume	Line 9	1,350	1,395	3,453	1,305	1,395	3,120	12,018
2	City Gate Delivered Volume	Line 15	1,350	1,395	3,453	1,305	1,395	3,120	12,018
3	Total Withdrawal Costs	Line 16	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 81,501
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 81,501
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.460	$ 6.533	$ 6.945	$ 7.132	$ 7.011	$ 6.602	$ 6.782
7									
8	Northern LNG Withdrawn Inventory								
9	Gross Withdrawn Volume	Sendout Optimization	1,350	1,395	3,453	1,305	1,395	3,120	12,018
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	Sch 14	$ 6.4599	$ 6.5330	$ 6.9451	$ 7.1321	$ 7.0115	$ 6.6025	$ 6.7818
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 81,501
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	1,350	1,395	3,453	1,305	1,395	3,120	12,018
16	Total Withdrawal Costs	Line 11 plus Line 13	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 81,501

Source of Supply: LNG Supply
Delivered to Northern via LNG Trucking Contract

Line	LNG Storage Deliveries	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2011-2012 Peak
1	Purchased Volumes	Line 22	1,350	1,395	2,482	1,305	1,395	4,091	12,018
2	Storage Delivered Volume	Line 24	1,350	1,395	2,482	1,305	1,395	4,091	12,018
3	Total Purchase Price	Line 15	$ 4.471	$ 6.052	$ 7.567	$ 7.394	$ 5.266	$ 4.739	$ 5.795
4	Total Purchase Cost	Line 10 times Line 12	$ 6,036	$ 8,443	$ 18,780	$ 9,649	$ 7,346	$ 19,386	$ 69,640
5	Variable Transportation Costs	Line 26	$ 1,337	$ 1,381	$ 2,457	$ 1,292	$ 1,381	$ 4,050	$ 11,897
6	Total Storage Delivered Costs	Line 13 plus Line 14	$ 7,372	$ 9,824	$ 21,237	$ 10,941	$ 8,727	$ 23,436	$ 81,537
7	Average Delivered Price	Line 15 divided by Line 11	$ 5.461	$ 7.042	$ 8.557	$ 8.384	$ 6.256	$ 5.729	$ 6.785
8									
9	Peaking Supply 1 Costs (Segment 1)								
10	Purchased Volumes	Sendout Optimization	1,350	1,395	2,482	1,305	1,395	4,091	12,018
11	Peaking Supply 1 Prices	Att to Sch 5A, Line 15 of Pag	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.315
12	Peaking Supply 1 Costs	Line 9 times Line 10	$ 5,458	$ 5,941	$ 10,878	$ 5,729	$ 6,081	$ 17,770	$ 51,857
13	NYMEX Basis Price	Att to Sch 5A, Line 11 of Pag	$ 0.428	$ 1.793	$ 3.184	$ 3.004	$ 0.907	$ 0.395	$ 1.480
14	NYMEX Basis Costs	Line 19 times Line 22	$ 578	$ 2,501	$ 7,902	$ 3,920	$ 1,265	$ 1,616	$ 17,782
15	Total Purchase Price	Line 20 plus Line 22	$ 4.471	$ 6.052	$ 7.567	$ 7.394	$ 5.266	$ 4.739	$ 5.795
16	Total Purchase Cost	Line 14 times (1 - Line 15)	$ 6,036	$ 8,443	$ 18,780	$ 9,649	$ 7,346	$ 19,386	$ 69,640
17									
18	Transportation Segment 3								
19	Trucking Contract (TransGas)								
20	Receipt Point: Distrigas Terminal								
21	Delivery Point: Northern LNG Facility (Lewiston, ME)								
22	Received Volume	Line 19 minus Line 31	1,350	1,395	2,482	1,305	1,395	4,091	12,018
23	Fuel Loss Rate	N/A	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Storage Delivered Volume	Line 22 times (1 - Line 23)	1,350	1,395	2,482	1,305	1,395	4,091	12,018
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Pag	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900
26	Variable Transportation Costs	Line 24 times Line 25	$ 1,337	$ 1,381	$ 2,457	$ 1,292	$ 1,381	$ 4,050	$ 11,897

Schedule 7

Northern Utilities, Inc. Hedging Gains and Losses November 2011 through April 2012 As of 9/6/2011							
Description	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter
NYMEX Contracts	9	16	21	22	17	11	96
Average Purchase Price	$ 5.021	$ 5.379	$ 5.436	$ 5.418	$ 5.414	$ 4.971	$ 5.326
Current NYMEX Price	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344	$ 4.323
Hedging (Gains) and Losses	$ 87,980	$ 179,160	$ 221,170	$ 226,200	$ 179,370	$ 69,010	$ 962,890

Schedule 8

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Winter 2011-2012 vs. Winter 2010-2011

			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 2011- 2012																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4395	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$131.85								
Over	50 units @	$0.3283	$19.37	$32.83	$44.98	$45.31	$38.08	$26.92	$207.49								
	CGA 1	$1.1149	$121.52						$121.52								
	CGA 2	$1.1149		$167.24					$167.24								
	CGA 3	$1.1149			$208.49				$208.49								
	CGA 4	$1.1149				$209.60			$209.60								
	CGA 5	$1.1149					$185.07		$185.07								
	CGA 6	$1.1149						$147.17	$147.17								
	LDAC	$0.0424	$4.62	$6.36	$7.93	$7.97	$7.04	$5.60	$39.52								
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				$53.33	
Temp Rate		$0.4395											$13.19	$18.46	$21.98	$53.62	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00				$13.46	
Temp Rate		$0.3283											$0.00	$0.00	$6.89	$6.89	
	CGA 1	$0.6673								$60.06						$60.06	
	CGA 2	$0.6673									$36.70					$36.70	
	CGA 3	$0.5992										$17.98				$17.98	
	CGA 4	$0.6685											$20.06			$20.06	
	CGA 5	$0.5570												$23.39		$23.39	
	CGA 6	$0.5570													$39.55	$39.55	
	LDAC	$ 0.0456								$4.10	$2.51	$1.37	$1.37	$1.92	$3.24	$14.50	
		TOTAL	$176.99	$237.90	$292.87	$294.35	$261.67	$211.16	$1,474.94	$106.13	$70.71	$41.15	$44.11	$53.27	$81.15	$396.53	$1,871.46

			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	$ 0.0456	$4.97	$6.84	$8.53	$8.57	$7.57	$6.02	$42.50								
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	$172.38	$227.79	$288.92	$298.21	$265.07	$213.87	$1,466.24	$103.55	$65.97	$44.54	$44.54	$58.55	$90.09	$407.23	$1,873.46
		Change	$4.61	$10.11	$3.95	($3.85)	($3.40)	($2.71)	$8.70	$2.58	$4.75	($3.39)	($0.43)	($5.28)	($8.93)	**($10.70)**	($2.00)
		% Chg	2.67%	4.44%	1.37%	-1.29%	-1.28%	-1.27%	0.59%	2.49%	7.20%	-7.60%	-0.96%	-9.02%	-9.91%	**-2.63%**	-0.11%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Winter 2011-2012 vs. Winter 2010-2011

			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 2011 - 2012																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3370	$25.28	$25.28	$25.28	$25.28	$25.28	$25.28	$151.65								
Over	75 units @	$0.2300	$27.14	$44.62	$51.29	$43.01	$36.57	$22.08	$224.71								
CGA 1		$1.1477	$221.51						$221.51								
CGA 2		$1.1477		$308.73					$308.73								
CGA 3		$1.1477			$342.01				$342.01								
CGA 4		$1.1477				$300.70			$300.70								
CGA 5		$1.1477					$268.56		$268.56								
CGA 6		$1.1477						$196.26	$196.26								
LDAC		$0.0203	$3.92	$5.46	$6.05	$5.32	$4.75	$3.47	$28.97								
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				$68.31	
Temp Rate		$0.3370											$24.26	$25.28	$25.28	$74.81	
Over	75 units @	$0.2007								$8.43	$1.20	$0.00				$9.63	
Temp Rate		$0.2300											$0.00	$3.22	$15.41	$18.63	
CGA 1		$0.7234								$84.64						$84.64	
CGA 2		$0.7234									$58.60					$58.60	
CGA 3		$0.6553										$47.18				$47.18	
CGA 4		$0.7246											$52.17			$52.17	
CGA 5		$0.6131												$54.57		$54.57	
CGA 6		$0.6131													$87.06	$87.06	
LDAC		$ 0.0166								$1.94	$1.34	$1.20	$1.20	$1.48	$2.36	$9.51	
		TOTAL	$296.54	$402.79	$443.33	$393.00	$353.86	$265.78	$2,155.30	$136.79	$102.92	$89.23	$96.33	$103.24	$148.80	$677.31	$2,832.61
			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		$1.0980	$211.91						$211.91								
CGA 2		$1.1058		$297.46					$297.46								
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		$ 0.0249	$4.81	$6.70	$7.42	$6.52	$5.83	$4.26	$35.53								
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		$ 0.0297								$3.47	$2.41	$2.14	$2.14	$2.64	$4.22	$17.02	
		TOTAL	$282.18	$384.87	$434.96	$396.54	$357.02	$268.09	$2,123.65	$134.47	$96.65	$98.00	$98.00	$115.23	$167.93	$710.28	$2,833.93
		Change	$14.36	$17.92	$8.37	($3.54)	($3.16)	($2.31)	$31.64	$2.32	$6.27	($8.77)	($1.67)	($11.99)	($19.13)	**($32.97)**	($1.33)
		% Chg	5.09%	4.65%	1.93%	-0.89%	-0.88%	-0.86%	1.49%	1.72%	6.49%	-8.95%	-1.70%	-10.40%	-11.39%	**-4.64%**	-0.05%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Winter 2011-2012 vs. Winter 2010-2011

			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 2011 - 2012																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.2235	$347.10	$576.18	$729.73	$917.02	$760.35	$552.72	$3,883.09								
	CGA 1	$1.1477	$1,782.38						$1,782.38								
	CGA 2	$1.1477		$2,958.77					$2,958.77								
	CGA 3	$1.1477			$3,747.24				$3,747.24								
	CGA 4	$1.1477				$4,709.01			$4,709.01								
	CGA 5	$1.1477					$3,904.48		$3,904.48								
	CGA 6	$1.1477						$2,838.26	$2,838.26								
	LDAC	$0.0203	$31.53	$52.33	$66.28	$83.29	$69.06	$50.20	$352.69								
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				$266.73	
Temp Rate		$0.1417											$30.18	$51.58	$99.05	$180.81	
	CGA 1	$0.7234								$910.04						$910.04	
	CGA 2	$0.7234									$507.10					$507.10	
	CGA 3	$0.6553										$271.29				$271.29	
	CGA 4	$0.7246											$154.34			$154.34	
	CGA 5	$0.6131												$223.17		$223.17	
	CGA 6	$0.6131													$428.56	$428.56	
	LDAC	$ 0.0166								$20.88	$11.64	$6.87	$3.54	$6.04	$11.60	$60.57	
		TOTAL	$2,221.30	$3,647.59	$4,603.55	$5,769.62	$4,794.18	$3,501.48	$24,537.72	$1,132.62	$657.83	$385.00	$248.36	$341.09	$599.51	$3,364.41	$27,902.13

			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	$1.0980	$1,705.19						$1,705.19								
	CGA 2	$1.1058		$2,850.75					$2,850.75								
	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	$ 0.0249	$38.67	$64.19	$81.30	$102.16	$84.71	$61.58	$432.61								
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	$ 0.0297								$37.36	$20.82	$12.30	$6.33	$10.81	$20.76	$108.38	
	TOTAL		$2,105.76	$3,475.89	$4,511.80	$5,825.02	$4,840.11	$3,534.87	$24,293.44	$1,107.71	$603.58	$435.43	$253.30	$390.12	$693.66	$3,483.79	$27,777.23
	Change		$115.54	$171.69	$91.75	($55.39)	($45.93)	($33.39)	$244.28	$24.91	$54.26	($50.43)	($4.94)	($49.03)	($94.16)	**($119.39)**	$124.89
	% Chg		5.49%	4.94%	2.03%	-0.95%	-0.95%	-0.94%	1.01%	2.25%	8.99%	-11.58%	-1.95%	-12.57%	-13.57%	**-3.43%**	0.45%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Winter 2011-2012 vs. Winter 2010-2011

			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 2011 - 2012																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.2155	$280.15	$280.15	$280.15	$280.15	$280.15	$280.15	$1,680.90								
Over	1,300 units @	$0.1760	$74.27	$138.34	$181.28	$181.81	$174.42	$100.67	$850.78								
	CGA 1	$0.9542	$1,643.13						$1,643.13								
	CGA 2	$0.9542		$1,990.46					$1,990.46								
	CGA 3	$0.9542			$2,223.29				$2,223.29								
	CGA 4	$0.9542				$2,226.15			$2,226.15								
	CGA 5	$0.9542					$2,186.07		$2,186.07								
	CGA 6	$0.9542						$1,786.26	$1,786.26								
	LDAC	$0.0203	$34.96	$42.35	$47.30	$47.36	$46.51	$38.00	$256.47								
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				$333.60	
Temp Rate		$0.1405											$140.50	$140.50	$140.50	$421.50	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27				$88.22	
Temp Rate		$0.1073											$20.39	$22.53	$34.77	$77.69	
	CGA 1	$0.5975								$902.23						$902.23	
	CGA 2	$0.5975									$820.97					$820.97	
	CGA 3	$0.5294										$660.16				$660.16	
	CGA 4	$0.5987											$712.45			$712.45	
	CGA 5	$0.4872												$589.51		$589.51	
	CGA 6	$0.4872													$645.05	$645.05	
	LDAC	$ 0.0166								$25.07	$22.81	$20.70	$19.75	$20.09	$21.98	$130.39	
		TOTAL	$2,092.81	$2,511.59	$2,792.32	$2,795.77	$2,747.45	$2,265.39	$15,205.32	$1,138.57	$1,044.45	$871.63	$953.39	$832.93	$902.60	$5,743.57	$20,948.88

			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	$ 0.0249	$42.88	$51.94	$58.02	$58.09	$57.05	$46.61	$314.59								
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	$ 0.0297								$44.85	$40.81	$37.04	$35.34	$35.94	$39.32	$233.29	
		TOTAL	$2,077.83	$2,441.09	$2,821.44	$2,921.98	$2,871.39	$2,366.66	$15,500.39	$1,173.45	$997.04	$1,077.01	$1,032.05	$1,047.83	$1,137.74	$6,465.12	$21,965.51
		Change	$14.98	$70.51	($29.12)	($126.22)	($123.94)	($101.28)	($295.07)	($34.88)	$47.40	($205.38)	($78.66)	($214.90)	($235.14)	**($721.56)**	($1,016.63)
		% Chg	0.72%	2.89%	-1.03%	-4.32%	-4.32%	-4.28%	-1.90%	-2.97%	4.75%	-19.07%	-7.62%	-20.51%	-20.67%	**-11.16%**	-4.63%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Winter 2011-2012 vs. Actual Winter 2010-2011

Residential Heating	Winter 2010-2011	Winter 2011- 2012
Customer Charge	$9.50	$9.50
First 50 Therms	$0.4102	$0.4395
Over 50 therms	$0.2990	$0.3283
LDAC	$0.0456	$0.0424
CGA	$1.1295	$1.1149

	Usage (Therms)	Winter 2010-2011 Bill Amount	Winter 2011-2012 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$17.43	$17.48	$0.06	0.3%	$0.15	0.9%	($0.07)	-0.4%	($0.02)	-0.1%
	10	$25.35	$25.47	$0.12	0.5%	$0.29	1.1%	($0.15)	-0.6%	($0.03)	-0.1%
	20	$41.21	$41.44	$0.23	0.6%	$0.59	1.4%	($0.29)	-0.7%	($0.06)	-0.1%
	25	$49.13	$49.42	$0.29	0.6%	$0.73	1.5%	($0.36)	-0.7%	($0.08)	-0.2%
	30	$57.06	$57.40	$0.35	0.6%	$0.88	1.5%	($0.44)	-0.8%	($0.10)	-0.2%
	45	$80.84	$81.36	$0.52	0.6%	$1.32	1.6%	($0.65)	-0.8%	($0.14)	-0.2%
Average Monthly	50	$88.76	$89.34	$0.58	0.7%	$1.47	1.7%	($0.73)	-0.8%	($0.16)	-0.2%
	75	$125.61	$126.48	$0.87	0.7%	$2.20	1.8%	($1.09)	-0.9%	($0.24)	-0.2%
	125	$199.32	$200.76	$1.44	0.7%	$3.67	1.8%	($1.82)	-0.9%	($0.40)	-0.2%
	150	$236.17	$237.90	$1.73	0.7%	$4.40	1.9%	($2.18)	-0.9%	($0.48)	-0.2%
	200	$309.87	$312.18	$2.31	0.7%	$5.87	1.9%	($2.91)	-0.9%	($0.64)	-0.2%

Schedule 9

Unitil
Northern Utilities, Inc.

Northern Utilities New Hampshire Division
Period Covered: May 1, 2012 - October 31, 2012
Variance Analysis

		2010 -2011 Winter (6 months actual)			Forecast 2011-2012 Winter (6 months proposed)			Variance		
1	Therm Sales	28,733,120			28,614,458			-118,662		
2				EFFECT			EFFECT			EFFECT
3		THERM		ON COST	THERM		ON COST	THERM		ON COST
4		SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS
5										
6	Demand Charges		$ 15,150,769	$ 0.5273		$ 16,876,488	0.5898		$ 1,725,719	$ 0.0625
7										
8	Purchased Gas		6,634,727	0.2309		7,934,188	0.2773		$ 1,299,461	$ 0.0464
9										
10	Storage & Peaking Gas		8,799,329	0.3062		6,076,270	0.2123		$ (2,723,059)	$ (0.0939)
11										
12	Hedging (Gain)/Loss		1,247,662	0.0434		506,830	0.0177		(740,832)	(0.0257)
13			16,681,718							
14										
15	Total Volumes and Cost	$ -	$ 31,832,486	$ 1.1079	$ -	$ 31,393,776	$ 1.0971	$ -	$ (438,711)	$ (0.0107)
16										
17	Prior Period Balance		$2,527,403	$ 0.0880		$ 973,628	$ 0.0340		$ (1,553,775)	$ (0.0539)
18	NHPUC Consultant Costs					$ -	$ -		$ -	$ -
19	Interest		$138,854	$ 0.0048		73,830	$ 0.0026		(65,024)	$ (0.0023)
20	Refunds from Suppliers		-	$ -		-	$ -		-	$ -
21										
22	Prior Period Adjustment									
23	Interruptible Sales Margin		-	$ -		-	$ -		-	$ -
24	Capacity Release		(1,582,206)	$ (0.0551)		(1,612,415)	$ (0.0563)		(30,210)	$ (0.0013)
25	Working Capital Allowance		(35,228)	$ (0.0012)		(10,682)	$ (0.0004)		24,545	$ 0.0009
26	Bad Debt Allowance		1,935	$ 0.0001		379,392	$ 0.0133		377,457	$ 0.0132
27	Fuel Inventory Financing		8,312	$ 0.0003		7,294	$ 0.0003		(1,018)	$ (0.0000)
28	Local Production and Storage		686,673	$ 0.0239		349,700	$ 0.0122		(336,973)	$ (0.0117)
29	Misc Overhead		98,333	$ 0.0034		349,601	$ 0.0122		251,268	$ 0.0088
30										
31	Total Anticipated Indirect Cost of Gas		$1,844,078	$ 0.0642		510,349	$ 0.0178		(1,333,730)	$ (0.0463)
32	Total Adjusted Cost	-	$33,676,565	$ 1.1720		$31,904,124	$ 1.1149		($1,772,440)	$ (0.0572)

Schedule 10A, 10B, and Attachments

Northern Utilities, Inc.

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

Base Capacity Costs

LN	BASE SENDOUT BY CLASS	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
2	**Total Therms**								
3	Res Heat	462,979	478,412	478,412	447,547	478,412	462,979	2,808,740	Schedule 10B, LN 52
4	Res General	17,000	17,566	17,566	16,433	17,566	17,000	103,131	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	102,901	106,331	106,331	99,471	106,331	102,901	624,268	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	131,927	136,324	136,324	127,529	136,324	131,927	800,356	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	137,598	142,185	142,185	133,011	142,185	137,598	834,762	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	163,970	169,435	169,435	158,504	169,435	163,970	994,750	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	5,811	6,005	6,005	5,617	6,005	5,811	35,254	Schedule 10B, LN 58
10	G42 High Annual-High Winter	20,222	20,896	20,896	19,548	20,896	20,222	122,682	Schedule 10B, LN 59
11	Total Firm Sales	1,042,408	1,077,155	1,077,155	1,007,661	1,077,155	1,042,408	6,323,942	Sum LN 3 : LN 10
12									
13	**% of Total**								
14	Res Heat	44.41%	44.41%	44.41%	44.41%	44.41%	44.41%		LN 3 / LN 11
15	Res General	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%		LN 4 / LN 11
16	G50 Low Annual-Low Winter	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%		LN 5 / LN 11
17	G40 Low Annual-High Winter	12.66%	12.66%	12.66%	12.66%	12.66%	12.66%		LN 6 / LN 11
18	G51 Med Annual-Low Winter	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%		LN 7 / LN 11
19	G41 Med Annual-High Winter	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%		LN 8 / LN 11
20	G52 High Annual-Low Winter	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%		LN 9 / LN 11
21	G42 High Annual-High Winter	1.94%	1.94%	1.94%	1.94%	1.94%	1.94%		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**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 85,599	$ 85,599	$ 85,599	$ 85,599	$ 85,599	$ 85,599	$ 513,596	Schedule 1A, LN 69
26	Res Heat	$ 38,018	$ 38,018	$ 38,018	$ 38,018	$ 38,018	$ 38,018	$ 228,110	LN 25 * LN 14
27	Res General	$ 1,396	$ 1,396	$ 1,396	$ 1,396	$ 1,396	$ 1,396	$ 8,376	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 8,450	$ 8,450	$ 8,450	$ 8,450	$ 8,450	$ 8,450	$ 50,700	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 10,833	$ 10,833	$ 10,833	$ 10,833	$ 10,833	$ 10,833	$ 65,000	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 11,299	$ 11,299	$ 11,299	$ 11,299	$ 11,299	$ 11,299	$ 67,795	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 13,465	$ 13,465	$ 13,465	$ 13,465	$ 13,465	$ 13,465	$ 80,788	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 477	$ 477	$ 477	$ 477	$ 477	$ 477	$ 2,863	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,661	$ 1,661	$ 1,661	$ 1,661	$ 1,661	$ 1,661	$ 9,964	LN 25 * LN 21
34									
35	Residential	$ 39,414	$ 39,414	$ 39,414	$ 39,414	$ 39,414	$ 39,414	$ 236,486	LN 26 + LN 27
36	SALES HLF CLASSES	$ 20,226	$ 20,226	$ 20,226	$ 20,226	$ 20,226	$ 20,226	$ 121,357	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 25,959	$ 25,959	$ 25,959	$ 25,959	$ 25,959	$ 25,959	$ 155,752	LN 29 + LN 31 + LN 33
38									

Remaining Capacity Costs

LN		Column A	Column B	Column C	Column D	
39		Design Day Demand (MMBtu)	Avg Daily Base Use Load (MMBtu)	Remaining Design Day Demand (MMBtu)	% of Total Remaining Design Day Demand	
40	Res Heat	19,246	1,537	17,709	49.38%	Company Analysis
41	Res General	348	56	292	0.81%	Company Analysis
42	G50 Low Annual-Low Winter	1,074	342	732	2.04%	Company Analysis
43	G40 Low Annual-High Winter	8,482	438	8,044	22.43%	Company Analysis
44	G51 Med Annual-Low Winter	1,436	457	979	2.73%	Company Analysis
45	G41 Med Annual-High Winter	7,609	544	7,065	19.70%	Company Analysis
46	G52 High Annual-Low Winter	54	19	35	0.10%	Company Analysis
47	G42 High Annual-High Winter	1,074	67	1,008	2.81%	Company Analysis
48	TOTAL	39,324	3,460	35,864	100.00%	Sum LN 40 : LN 47

49

50 **REMAINING PIPELINE DEMAND**

LN		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
51		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 193,263	$ 406,892	$ 734,311	$ 425,107	$ 317,335	$ 148,376	$ 2,225,283	Schedule 1A, LN 70
53									
54	Res Heat	$ 95,432	$ 200,920	$ 362,598	$ 209,915	$ 156,698	$ 73,267	$ 1,098,829	LN 40 Col D * LN 52
55	Res General	$ 1,573	$ 3,312	$ 5,976	$ 3,460	$ 2,583	$ 1,208	$ 18,111	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 3,945	$ 8,305	$ 14,988	$ 8,677	$ 6,477	$ 3,028	$ 45,419	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 43,347	$ 91,261	$ 164,698	$ 95,347	$ 71,175	$ 33,279	$ 499,107	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 5,276	$ 11,108	$ 20,047	$ 11,605	$ 8,663	$ 4,051	$ 60,751	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 38,073	$ 80,158	$ 144,660	$ 83,746	$ 62,515	$ 29,230	$ 438,382	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 188	$ 396	$ 715	$ 414	$ 309	$ 144	$ 2,166	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 5,430	$ 11,431	$ 20,630	$ 11,943	$ 8,915	$ 4,169	$ 62,518	LN 47 Col D * LN 52
62	TOTAL	$ 193,263	$ 406,892	$ 734,311	$ 425,107	$ 317,335	$ 148,376	$ 2,225,283	Sum LN 54 : LN 61
63									
64	Residential	$ 97,005	$ 204,232	$ 368,574	$ 213,375	$ 159,280	$ 74,475	$ 1,116,940	LN 54 + LN 55
65	SALES HLF CLASSES	$ 9,409	$ 19,809	$ 35,749	$ 20,696	$ 15,449	$ 7,224	$ 108,336	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 86,849	$ 182,851	$ 329,988	$ 191,036	$ 142,605	$ 66,678	$ 1,000,007	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

LN		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
69		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 1,227,831	$ 2,585,053	$ 4,665,206	$ 2,700,778	$ 2,016,083	$ 942,659	$ 14,137,610	Schedule 1A, LN 73
71									
72	Res Heat	$ 606,295	$ 1,276,481	$ 2,303,647	$ 1,333,626	$ 995,528	$ 465,479	$ 6,981,055	LN 40 Col D * LN 70
73	Res General	$ 9,993	$ 21,039	$ 37,968	$ 21,981	$ 16,408	$ 7,672	$ 115,060	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 25,061	$ 52,762	$ 95,219	$ 55,124	$ 41,149	$ 19,240	$ 288,555	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 275,389	$ 579,799	$ 1,046,355	$ 605,755	$ 452,185	$ 211,428	$ 3,170,911	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 33,520	$ 70,572	$ 127,361	$ 73,732	$ 55,039	$ 25,735	$ 385,959	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 241,884	$ 509,257	$ 919,048	$ 532,055	$ 397,170	$ 185,704	$ 2,785,118	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 1,195	$ 2,517	$ 4,542	$ 2,629	$ 1,963	$ 918	$ 13,764	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 34,495	$ 72,626	$ 131,067	$ 75,877	$ 56,641	$ 26,484	$ 397,189	LN 47 Col D * LN 70
80	TOTAL	$ 1,227,831	$ 2,585,053	$ 4,665,206	$ 2,700,778	$ 2,016,083	$ 942,659	$ 14,137,610	Sum LN 72 : LN 79
81									
82	Residential	$ 616,288	$ 1,297,520	$ 2,341,615	$ 1,355,606	$ 1,011,936	$ 473,150	$ 7,096,115	LN 72 + LN 73
83	SALES HLF CLASSES	$ 59,776	$ 125,851	$ 227,122	$ 131,485	$ 98,151	$ 45,893	$ 688,277	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 551,768	$ 1,161,682	$ 2,096,470	$ 1,213,687	$ 905,996	$ 423,616	$ 6,353,218	LN 75 + LN 77 + LN 79

85

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

LN		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
87		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ (143,589)	$ (294,109)	$ (524,803)	$ (306,943)	$ (231,008)	$ (111,963)	$ (1,612,415)	Schedule 1A, LN 76
89									
90	Res Heat	$ (70,903)	$ (145,229)	$ (259,144)	$ (151,566)	$ (114,070)	$ (55,286)	$ (796,200)	LN 40 Col D * LN 88
91	Res General	$ (1,169)	$ (2,394)	$ (4,271)	$ (2,498)	$ (1,880)	$ (911)	$ (13,123)	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ (2,931)	$ (6,003)	$ (10,711)	$ (6,265)	$ (4,715)	$ (2,285)	$ (32,910)	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ (32,205)	$ (65,965)	$ (117,708)	$ (68,844)	$ (51,813)	$ (25,112)	$ (361,647)	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ (3,920)	$ (8,029)	$ (14,327)	$ (8,380)	$ (6,307)	$ (3,057)	$ (44,019)	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ (28,287)	$ (57,940)	$ (103,387)	$ (60,468)	$ (45,509)	$ (22,057)	$ (317,647)	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ (140)	$ (286)	$ (511)	$ (299)	$ (225)	$ (109)	$ (1,570)	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ (4,034)	$ (8,263)	$ (14,744)	$ (8,623)	$ (6,490)	$ (3,146)	$ (45,300)	LN 47 Col D * LN 88
98	TOTAL	$ (143,589)	$ (294,109)	$ (524,803)	$ (306,943)	$ (231,008)	$ (111,963)	$ (1,612,415)	Sum LN 90 : LN 97
99									
100	Residential	$ (72,072)	$ (147,622)	$ (263,415)	$ (154,064)	$ (115,950)	$ (56,198)	$ (809,322)	LN 90 + LN 91
101	SALES HLF CLASSES	$ (6,991)	$ (14,318)	$ (25,550)	$ (14,943)	$ (11,246)	$ (5,451)	$ (78,499)	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ (64,527)	$ (132,168)	$ (235,838)	$ (137,935)	$ (103,812)	$ (50,314)	$ (724,594)	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

LN		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
105		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
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		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
123		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
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		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
141		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
142	Res Heat	$ 630,823	$ 1,332,173	$ 2,407,100	$ 1,391,974	$ 1,038,155	$ 483,459	$ 7,283,684	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 10,397	$ 21,957	$ 39,673	$ 22,942	$ 17,111	$ 7,968	$ 120,048	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 26,074	$ 55,064	$ 99,495	$ 57,536	$ 42,911	$ 19,983	$ 301,063	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 286,530	$ 605,095	$ 1,093,345	$ 632,258	$ 471,547	$ 219,595	$ 3,308,371	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 34,876	$ 73,651	$ 133,081	$ 76,958	$ 57,396	$ 26,729	$ 402,691	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 251,669	$ 531,475	$ 960,322	$ 555,333	$ 414,176	$ 192,878	$ 2,905,853	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 1,244	$ 2,626	$ 4,746	$ 2,744	$ 2,047	$ 953	$ 14,360	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 35,891	$ 75,794	$ 136,953	$ 79,197	$ 59,066	$ 27,507	$ 414,407	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 1,277,505	$ 2,697,836	$ 4,874,714	$ 2,818,942	$ 2,102,409	$ 979,072	$ 14,750,477	Sum LN 142 : LN 149
151									
152	Residential	$ 641,220	$ 1,354,129	$ 2,446,773	$ 1,414,916	$ 1,055,266	$ 491,427	$ 7,403,732	LN 142 + LN 143
153	SALES HLF CLASSES	$ 62,194	$ 131,342	$ 237,321	$ 137,238	$ 102,354	$ 47,665	$ 718,114	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 574,090	$ 1,212,365	$ 2,190,619	$ 1,266,788	$ 944,789	$ 439,980	$ 6,628,631	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
157		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
158	Res Heat	$ 668,842	$ 1,370,191	$ 2,445,118	$ 1,429,993	$ 1,076,173	$ 521,477	$ 7,511,795	LN 142 + LN 26
159	Res General	$ 11,793	$ 23,353	$ 41,069	$ 24,338	$ 18,507	$ 9,364	$ 128,424	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 34,524	$ 63,514	$ 107,945	$ 65,986	$ 51,361	$ 28,433	$ 351,763	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 297,364	$ 615,928	$ 1,104,178	$ 643,091	$ 482,381	$ 230,429	$ 3,373,371	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 46,175	$ 84,950	$ 144,380	$ 88,257	$ 68,695	$ 38,028	$ 470,485	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 265,134	$ 544,940	$ 973,786	$ 568,798	$ 427,641	$ 206,342	$ 2,986,641	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,721	$ 3,104	$ 5,223	$ 3,222	$ 2,524	$ 1,430	$ 17,224	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 37,551	$ 77,455	$ 138,613	$ 80,857	$ 60,727	$ 29,167	$ 424,370	LN 149 + LN 33
166	TOTAL	$ 1,363,104	$ 2,783,435	$ 4,960,313	$ 2,904,541	$ 2,188,008	$ 1,064,671	$ 15,264,073	Sum LN 158 : LN 165
167									
168	Residential	$ 680,635	$ 1,393,544	$ 2,486,188	$ 1,454,331	$ 1,094,680	$ 530,842	$ 7,640,218	LN 158 + LN 159
169	SALES HLF CLASSES	$ 82,420	$ 151,568	$ 257,548	$ 157,464	$ 122,580	$ 67,892	$ 839,472	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 600,049	$ 1,238,323	$ 2,216,578	$ 1,292,746	$ 970,748	$ 465,938	$ 6,784,383	LN 161 + LN 163 + LN 165
171									
172	% ALLOCATION BETWEEN SALES HLF AND LLF								
173	SALES HLF CLASSES							11.01%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES							88.99%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2011 - 2012 Period

Line No.	**Forecasted Normal Sales By Class- Therms** Calendar Month Firm Sales Volumes Normal Winter	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12
1	Res Heat	1,703,736	2,515,331	2,874,218	2,520,436	2,235,457	1,469,786	598,377	481,043	469,565
2	Res General	27,273	40,265	46,010	40,347	35,785	23,528	21,971	17,663	17,241
3	**Total Residential**	**1,731,009**	**2,555,596**	**2,920,229**	**2,560,783**	**2,271,243**	**1,493,314**	**620,349**	**498,705**	**486,807**
4	G50 Low Annual-Low Winter	136,918	202,141	230,982	202,551	179,649	118,117	132,995	106,916	104,365
5	G40 Low Annual-High Winter	814,054	1,201,838	1,373,317	1,204,278	1,068,113	702,271	170,509	137,074	133,803
6	G51 Med Annual-Low Winter	183,076	270,286	308,851	270,835	240,212	157,937	177,839	142,967	139,555
7	G41 Med Annual-High Winter	688,478	1,016,443	1,161,469	1,018,506	903,346	593,939	211,923	170,367	166,302
8	G52 High Annual-Low Winter	7,427	8,655	10,417	10,125	9,124	8,050	6,742	6,320	5,941
9	G42 High Annual-High Winter	99,888	147,471	168,512	147,770	131,062	86,172	26,136	21,011	20,510
10	**Total C&I**	**1,929,842**	**2,846,834**	**3,253,548**	**2,854,065**	**2,531,508**	**1,666,487**	**726,143**	**584,655**	**570,478**
11	**Total Sales**	**3,660,851**	**5,402,430**	**6,173,777**	**5,414,848**	**4,802,750**	**3,159,801**	**1,346,492**	**1,083,360**	**1,057,284**
12										
13	Residential Heat & Non Heat	1,731,009	2,555,596	2,920,229	2,560,783	2,271,243	1,493,314	620,349	498,705	486,807
14	SALES HLF CLASSES	327,421	481,082	550,250	483,511	428,986	284,104	317,576	256,202	249,862
15	SALES LLF CLASSES	1,602,420	2,365,752	2,703,298	2,370,554	2,102,522	1,382,382	408,568	328,452	320,616
16	**Total Firm Sales**	**3,660,851**	**5,402,430**	**6,173,777**	**5,414,848**	**4,802,750**	**3,159,801**	**1,346,492**	**1,083,360**	**1,057,284**
17										
18	**ESTIMATED SENDOUT BY CLASS - Therms**									
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)									
20	Normal Winter	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**
21	Res Heat	1,719,950	2,539,150	2,901,403	2,544,320	2,256,696	1,483,893	604,318	485,860	474,262
22	Res General	27,533	40,647	46,446	40,729	36,125	23,754	22,189	17,840	17,414
23	G50 Low Annual-Low Winter	138,221	204,055	233,167	204,471	181,356	119,251	134,315	107,987	105,409
24	G40 Low Annual-High Winter	821,801	1,213,219	1,386,306	1,215,689	1,078,261	709,012	172,202	138,447	135,142
25	G51 Med Annual-Low Winter	184,818	272,846	311,772	273,401	242,495	159,453	179,604	144,398	140,951
26	G41 Med Annual-High Winter	695,030	1,026,068	1,172,454	1,028,157	911,929	599,640	214,027	172,073	167,966
27	G52 High Annual-Low Winter	7,498	8,737	10,516	10,221	9,211	8,128	6,809	6,383	6,001
28	G42 High Annual-High Winter	100,839	148,868	170,106	149,171	132,308	86,999	26,396	21,222	20,715
29	**Subtotal**									
30	Residential	1,747,483	2,579,797	2,947,849	2,585,049	2,292,821	1,507,648	626,507	503,700	491,676
31	SALES HLF CLASSES	330,537	485,638	555,455	488,093	433,061	286,831	320,728	258,768	252,361
32	SALES LLF CLASSES	1,617,670	2,388,155	2,728,866	2,393,018	2,122,498	1,395,651	412,624	331,742	323,823
33	**Total Firm Sales**	3,695,690	5,453,590	6,232,170	5,466,160	4,848,380	3,190,130	1,359,860	1,094,210	1,067,860

Aug-12	Sep-12	Oct-12	TOTAL	Winter
477,796	518,017	773,384	16,637,146	13,318,964
17,544	19,020	28,397	335,046	213,210
495,340	**537,038**	**801,781**	**16,972,192**	**13,532,174**
106,194	115,134	171,891	1,807,855	1,070,359
136,149	147,610	220,377	7,309,393	6,363,871
142,002	153,955	229,851	2,417,366	1,431,197
169,217	183,462	273,903	6,557,356	5,382,181
5,950	5,973	6,333	91,057	53,799
20,870	22,626	33,780	925,811	780,877
580,382	**628,761**	**936,136**	**19,108,838**	**15,082,284**
1,075,722	**1,165,799**	**1,737,916**	**36,081,030**	**28,614,458**
495,340	537,038	801,781	16,972,192	13,532,174
254,146	275,062	408,075	4,316,278	2,555,355
326,236	353,698	528,061	14,792,560	12,526,929
1,075,722	**1,165,799**	**1,737,916**	**36,081,030**	**28,614,458**

Aug-12	Sep-12	Oct-12	TOTAL	Winter
482,561	523,168	780,950	16,796,533	13,445,412
17,719	19,210	28,675	338,280	215,234
107,254	116,279	173,573	1,825,338	1,080,521
137,507	149,078	222,533	7,379,196	6,424,289
143,418	155,486	232,100	2,440,742	1,444,785
170,905	185,286	276,583	6,620,119	5,433,279
6,009	6,032	6,394	91,939	54,310
21,078	22,851	34,111	934,663	788,290
500,280	542,377	809,625	17,134,812	13,660,646
256,681	277,797	412,067	4,358,019	2,579,616
329,489	357,215	533,227	14,933,979	12,645,858
1,086,450	1,177,390	1,754,920	36,426,810	28,886,120

Northern Utilities - NEW HAMPSHIRE DIVISION
2011 - 2012 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

DAILY BASE GAS ENTITLEMENT - Therms/day		
Res Heat	15,433	15,433
Res General	567	567
G50 Low Annual-Low Winter	3,430	3,430
G40 Low Annual-High Winter	4,398	4,398
G51 Med Annual-Low Winter	4,587	4,587
G41 Med Annual-High Winter	5,466	5,466
G52 High Annual-Low Winter	194	194
G42 High Annual-High Winter	674	674
Subtotal		-
Residential	15,999	15,999
SALES HLF CLASSES	8,210	8,210
SALES LLF CLASSES	10,537	10,537
Total Firm Sales	**34,747**	**34,747**

BASE SENDOUT BY CLASS - Therms									
Days per Month	30	31	31	29	31	30	31	30	31
	Nov-11	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**
Res Heat	462,979	478,412	478,412	447,547	478,412	462,979	478,412	462,979	474,262
Res General	17,000	17,566	17,566	16,433	17,566	17,000	17,566	17,000	17,414
G50 Low Annual-Low Winter	102,901	106,331	106,331	99,471	106,331	102,901	106,331	102,901	105,409
G40 Low Annual-High Winter	131,927	136,324	136,324	127,529	136,324	131,927	136,324	131,927	135,142
G51 Med Annual-Low Winter	137,598	142,185	142,185	133,011	142,185	137,598	142,185	137,598	140,951
G41 Med Annual-High Winter	163,970	169,435	169,435	158,504	169,435	163,970	169,435	163,970	167,966
G52 High Annual-Low Winter	5,811	6,005	6,005	5,617	6,005	5,811	6,005	5,811	6,001
G42 High Annual-High Winter	20,222	20,896	20,896	19,548	20,896	20,222	20,896	20,222	20,715
Subtotal									
Residential	479,979	495,978	495,978	463,979	495,978	479,979	495,978	479,979	491,676
SALES HLF CLASSES	246,311	254,521	254,521	238,100	254,521	246,311	254,521	246,311	252,361
SALES LLF CLASSES	316,119	326,656	326,656	305,582	326,656	316,119	326,656	316,119	323,823
Total Firm Sales	1,042,408	1,077,155	1,077,155	1,007,661	1,077,155	1,042,408	1,077,155	1,042,408	1,067,860

REMAINING SENDOUT BY CLASS - Therms									
	Nov-11	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**
Res Heat	1,256,971	2,060,738	2,422,992	2,096,773	1,778,284	1,020,914	125,906	22,881	-
Res General	10,533	23,080	28,879	24,297	18,559	6,755	4,623	840	-
G50 Low Annual-Low Winter	35,320	97,724	126,836	104,999	75,025	16,350	27,984	5,086	-
G40 Low Annual-High Winter	689,874	1,076,895	1,249,981	1,088,160	941,937	577,085	35,877	6,520	-
G51 Med Annual-Low Winter	47,220	130,661	169,587	140,390	100,310	21,855	37,420	6,800	-
G41 Med Annual-High Winter	531,060	856,633	1,003,019	869,653	742,493	435,670	44,591	8,104	-
G52 High Annual-Low Winter	1,687	2,732	4,511	4,603	3,206	2,317	804	572	-
G42 High Annual-High Winter	80,616	127,971	149,210	129,623	111,411	66,777	5,499	999	-
Subtotal									
Residential	1,267,504	2,083,819	2,451,871	2,121,070	1,796,843	1,027,669	130,529	23,721	-
SALES HLF CLASSES	84,227	231,117	300,934	249,993	178,541	40,521	66,208	12,458	-
SALES LLF CLASSES	1,301,551	2,061,499	2,402,210	2,087,436	1,795,841	1,079,532	85,968	15,623	-
Total Firm Sales	2,653,282	4,376,435	5,155,015	4,458,499	3,771,225	2,147,722	282,705	51,802	-

31	30	31		
Aug-12	**Sep-12**	**Oct-12**	**TOTAL**	**WINTER**
478,412	462,979	478,412	5,644,196	2,808,740
17,566	17,000	17,566	207,242	103,131
106,331	102,901	106,331	1,254,473	624,268
136,324	131,927	136,324	1,608,324	800,356
142,185	137,598	142,185	1,677,463	834,762
169,435	163,970	169,435	1,998,961	994,750
6,005	5,811	6,005	70,892	35,254
20,896	20,222	20,896	246,532	122,682
495,978	479,979	495,978	5,851,438	2,911,871
254,521	246,311	254,521	3,002,829	1,494,284
326,656	316,119	326,656	3,853,817	1,917,788
1,077,155	1,042,408	1,077,155	12,708,083	6,323,942

Aug-12	Sep-12	Oct-12	TOTAL	WINTER
4,150	60,189	302,539	11,152,337	10,636,672
152	2,210	11,109	131,037	112,103
922	13,377	67,242	570,865	456,254
1,182	17,151	86,209	5,770,873	5,623,933
1,233	17,888	89,915	763,279	610,023
1,470	21,317	107,148	4,621,158	4,438,529
4	221	390	21,046	19,055
181	2,629	13,215	688,132	665,608
4,302	62,399	313,647	11,283,374	10,748,776
2,160	31,487	157,546	1,355,190	1,085,332
2,833	41,096	206,571	11,080,162	10,728,070
9,295	134,982	677,765	23,718,727	22,562,178

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)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 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)
Nov	536,250	519,737	16,512	3.2%	7,400	9,113	526,229	10,020	1.9%	12,921	-2,900
Dec	801,725	771,466	30,260	3.9%	7,088	23,172	784,485	17,240	2.2%	14,237	3,003
Jan	1,024,900	1,069,954	-45,053	-4.2%	20,256	-65,309	1,054,461	-29,560	-2.8%	29,404	-58,964
Feb	1,023,016	1,051,995	-28,979	-2.8%	19,667	-48,646	972,557	50,458	5.2%	27,406	23,052
Mar	916,768	936,327	-19,559	-2.1%	16,950	-36,509	866,984	49,784	5.7%	25,634	24,150
Apr	783,491	694,990	88,501	12.7%	15,021	73,480	693,563	89,928	13.0%	23,224	66,704
May	493,457	454,822	38,635	8.5%	10,004	28,631	419,071	74,386	17.8%	12,827	61,559
Jun	376,206	340,672	35,534	10.4%	7,894	27,640	305,140	71,067	23.3%	8,724	62,343
Jul	305,376	300,658	4,717	1.6%	5,957	-1,240	271,701	33,675	12.4%	9,498	24,176
Aug	283,044	278,381	4,663	1.7%	5,515	-852	283,312	-268	-0.1%	10,160	-10,428
Sep	301,907	297,295	4,612	1.6%	5,901	-1,289	294,853	7,054	2.4%	10,218	-3,164
Oct	365,582	358,551	7,031	2.0%	7,265	-234	371,383	-5,801	-1.6%	14,262	-20,063
Peak	5,086,150	5,044,468	41,682	0.8%	84,776	-43,094	4,898,280	187,870	3.8%	132,154	55,716
Off-Peak	2,125,572	2,030,379	95,193	4.7%	42,265	52,928	1,945,459	180,113	9.3%	65,827	114,286
Annual	7,211,722	7,074,847	136,875	1.9%	133,105	3,770	6,843,739	367,983	5.4%	208,104	159,879

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						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	28,709	28,306	403	1.4%	28,021	688	2.5%
Dec	28,668	28,407	261	0.9%	28,157	511	1.8%
Jan	29,010	28,471	539	1.9%	28,223	787	2.8%
Feb	29,044	28,511	533	1.9%	28,248	796	2.8%
Mar	29,076	28,559	517	1.8%	28,241	835	3.0%
Apr	29,259	28,640	619	2.2%	28,311	948	3.3%
May	29,226	28,597	629	2.2%	28,358	868	3.1%
Jun	29,142	28,482	660	2.3%	28,332	810	2.9%
Jul	29,131	28,565	566	2.0%	28,147	984	3.5%
Aug	29,086	28,521	565	2.0%	28,079	1,007	3.6%
Sep	29,080	28,514	566	2.0%	28,106	974	3.5%
Oct	29,257	28,676	581	2.0%	28,175	1,082	3.8%
Peak	28,961	28,482	479	1.7%	28,200	761	2.7%
Off-Peak	29,154	28,559	595	2.1%	28,200	954	3.4%
Annual	29,057	28,521	537	1.9%	28,200	858	3.0%

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						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	18.68	18.36	0.32	1.7%	18.78	-0.10	-0.5%
Dec	27.97	27.16	0.81	3.0%	27.86	0.10	0.4%
Jan	35.33	37.58	-2.25	-6.0%	37.36	-2.03	-5.4%
Feb	35.22	36.90	-1.67	-4.5%	34.43	0.79	2.3%
Mar	31.53	32.79	-1.26	-3.8%	30.70	0.83	2.7%
Apr	26.78	24.27	2.51	10.3%	24.50	2.28	9.3%
May	16.88	15.90	0.98	6.2%	14.78	2.11	14.3%
Jun	12.91	11.96	0.95	7.9%	10.77	2.14	19.9%
Jul	10.48	10.53	-0.04	-0.4%	9.65	0.83	8.6%
Aug	9.73	9.76	-0.03	-0.3%	10.09	-0.36	-3.6%
Sep	10.38	10.43	-0.04	-0.4%	10.49	-0.11	-1.0%
Oct	12.50	12.50	-0.01	-0.1%	13.18	-0.69	-5.2%
Peak	175.62	177.11	-1.49	-0.8%	173.70	1.88	1.1%
Off-Peak	72.91	71.09	1.82	2.6%	68.99	3.92	5.7%
Annual	248.19	248.06	0.13	0.1%	242.69	5.80	2.4%

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)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 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)
Nov	2,597	2,615	-18	-0.7%	-121	102	2,631	-34	-1.3%	-146	112
Dec	3,270	4,227	-957	-22.6%	-203	-755	3,172	98	3.1%	-206	304
Jan	4,330	4,441	-111	-2.5%	-180	70	4,859	-529	-10.9%	-286	-243
Feb	4,292	5,183	-891	-17.2%	-217	-674	4,430	-138	-3.1%	-269	130
Mar	3,903	4,482	-579	-12.9%	-188	-391	3,925	-23	-0.6%	-236	214
Apr	2,929	3,811	-882	-23.1%	-265	-617	3,617	-688	-19.0%	-320	-368
May	2,382	2,689	-307	-11.4%	-128	-179	2,567	-185	-7.2%	-166	-19
Jun	2,444	2,265	179	7.9%	-110	290	1,998	447	22.4%	-138	584
Jul	1,759	1,913	-154	-8.0%	-79	-75	1,877	-117	-6.2%	-139	22
Aug	1,844	2,005	-161	-8.0%	-83	-78	1,674	169	10.1%	-126	296
Sep	1,817	1,976	-159	-8.0%	-81	-77	1,915	-98	-5.1%	-142	44
Oct	1,937	2,059	-121	-5.9%	-89	-32	1,915	23	1.2%	-156	179
Peak	21,321	24,760	-3,439	-13.9%	-1,190	-2,249	22,635	-1,314	-5.8%	-1,467	153
Off-Peak	12,184	12,906	-722	-5.6%	-567	-155	11,945	239	2.0%	-872	1,111
Annual	33,505	37,666	-4,161	-11.0%	-1,732	-2,429	34,580	-1,075	-3.1%	-2,385	1,310

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						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	1,548	1,623	-75	-4.6%	1,639	-91	-5.6%
Dec	1,529	1,606	-77	-4.8%	1,635	-106	-6.5%
Jan	1,535	1,600	-65	-4.1%	1,631	-96	-5.9%
Feb	1,533	1,600	-67	-4.2%	1,632	-99	-6.1%
Mar	1,531	1,598	-67	-4.2%	1,629	-98	-6.0%
Apr	1,515	1,628	-113	-6.9%	1,662	-147	-8.8%
May	1,577	1,656	-79	-4.8%	1,686	-109	-6.5%
Jun	1,582	1,663	-81	-4.9%	1,699	-117	-6.9%
Jul	1,563	1,630	-67	-4.1%	1,688	-125	-7.4%
Aug	1,556	1,623	-67	-4.1%	1,683	-127	-7.5%
Sep	1,537	1,603	-66	-4.1%	1,660	-123	-7.4%
Oct	1,503	1,571	-68	-4.3%	1,636	-133	-8.1%
Peak	1,532	1,609	-77	-4.8%	1,638	-106	-6.5%
Off-Peak	1,553	1,624	-71	-4.4%	1,675	-122	-7.3%
Annual	1,542	1,617	-74	-4.6%	1,657	-114	-6.9%

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

	Total Division Use Per Meter						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	1.68	1.61	0.07	4.1%	1.61	0.07	4.5%
Dec	2.14	2.63	-0.49	-18.8%	1.94	0.20	10.2%
Jan	2.82	2.78	0.05	1.6%	2.98	-0.16	-5.3%
Feb	2.80	3.24	-0.44	-13.6%	2.71	0.09	3.1%
Mar	2.55	2.80	-0.26	-9.1%	2.41	0.14	5.8%
Apr	1.93	2.34	-0.41	-17.4%	2.18	-0.24	-11.2%
May	1.51	1.62	-0.11	-7.0%	1.52	-0.01	-0.8%
Jun	1.55	1.36	0.18	13.4%	1.18	0.37	31.4%
Jul	1.13	1.17	-0.05	-4.1%	1.11	0.01	1.2%
Aug	1.18	1.24	-0.05	-4.1%	0.99	0.19	19.1%
Sep	1.18	1.23	-0.05	-4.1%	1.15	0.03	2.5%
Oct	1.29	1.31	-0.02	-1.6%	1.17	0.12	10.1%
Peak	13.92	15.39	-1.47	-9.5%	13.82	0.09	0.7%
Off-Peak	7.85	7.95	-0.10	-1.3%	7.13	0.71	9.9%
Annual	21.72	23.30	-1.58	-6.8%	20.87	0.80	3.8%

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)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 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)
Nov	110,874	103,965	6,909	6.6%	1,908	5,001	112,790	-1,917	-1.7%	3,856	-5,773
Dec	191,389	187,186	4,202	2.2%	2,327	1,875	170,092	21,297	12.5%	4,584	16,713
Jan	278,439	286,003	-7,564	-2.6%	6,386	-13,949	295,848	-17,409	-5.9%	10,736	-28,145
Feb	293,812	305,506	-11,694	-3.8%	6,886	-18,581	270,406	23,406	8.7%	9,922	13,485
Mar	247,682	252,800	-5,118	-2.0%	5,726	-10,844	231,222	16,460	7.1%	8,811	7,649
Apr	209,701	183,768	25,932	14.1%	5,047	20,886	187,981	21,720	11.6%	8,131	13,589
May	112,759	97,907	14,852	15.2%	2,490	12,362	94,019	18,740	19.9%	3,492	15,248
Jun	67,629	57,942	9,687	16.7%	1,556	8,131	46,595	21,034	45.1%	1,632	19,402
Jul	38,202	38,873	-671	-1.7%	927	-1,598	35,665	2,537	7.1%	1,496	1,041
Aug	30,648	31,203	-555	-1.8%	745	-1,300	29,724	925	3.1%	1,266	-342
Sep	33,805	34,547	-743	-2.1%	824	-1,566	33,427	377	1.1%	1,405	-1,027
Oct	48,775	47,925	850	1.8%	1,173	-323	49,148	-374	-0.8%	2,290	-2,664
Peak	1,331,896	1,319,228	12,668	1.0%	27,670	-15,002	1,268,338	63,558	5.0%	45,567	17,991
Off-Peak	331,818	308,398	23,420	7.6%	7,624	15,796	288,579	43,239	15.0%	11,797	31,442
Annual	1,663,715	1,627,626	36,088	2.2%	37,194	-1,105	1,556,917	106,797	6.9%	59,795	47,002

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						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	20,810	20,435	375	1.8%	20,122	688	3.4%
Dec	20,767	20,512	255	1.2%	20,222	545	2.7%
Jan	21,017	20,558	459	2.2%	20,281	736	3.6%
Feb	21,049	20,585	464	2.3%	20,304	745	3.7%
Mar	21,085	20,618	467	2.3%	20,311	774	3.8%
Apr	21,250	20,682	568	2.7%	20,369	881	4.3%
May	21,167	20,642	525	2.5%	20,409	758	3.7%
Jun	21,104	20,552	552	2.7%	20,390	714	3.5%
Jul	21,117	20,625	492	2.4%	20,267	850	4.2%
Aug	21,093	20,601	492	2.4%	20,231	862	4.3%
Sep	21,127	20,635	492	2.4%	20,275	852	4.2%
Oct	21,268	20,760	508	2.4%	20,321	947	4.7%
Peak	20,996	20,565	431	2.1%	20,268	728	3.6%
Off-Peak	21,146	20,636	510	2.5%	20,316	831	4.1%
Annual	21,071	20,600	471	2.3%	20,292	779	3.8%

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

	Total Division Use Per Meter						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	5.33	5.09	0.24	4.7%	5.61	-0.28	-4.9%
Dec	9.22	9.13	0.09	1.0%	8.41	0.80	9.6%
Jan	13.25	13.91	-0.66	-4.8%	14.59	-1.34	-9.2%
Feb	13.96	14.84	-0.88	-5.9%	13.32	0.64	4.8%
Mar	11.75	12.26	-0.51	-4.2%	11.38	0.36	3.2%
Apr	9.87	8.89	0.98	11.1%	9.23	0.64	6.9%
May	5.33	4.74	0.58	12.3%	4.61	0.72	15.6%
Jun	3.20	2.82	0.39	13.7%	2.29	0.92	40.2%
Jul	1.81	1.88	-0.08	-4.0%	1.76	0.05	2.8%
Aug	1.45	1.51	-0.06	-4.1%	1.47	-0.02	-1.1%
Sep	1.60	1.67	-0.07	-4.4%	1.65	-0.05	-2.9%
Oct	2.29	2.31	-0.02	-0.7%	2.42	-0.13	-5.2%
Peak	63.43	64.15	-0.71	-1.1%	62.58	0.83	1.3%
Off-Peak	15.69	14.94	0.75	5.0%	14.20	1.50	10.6%
Annual	78.96	79.01	-0.05	-0.1%	76.73	2.33	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

	Total Division C&I Metered Deliveries (Dth)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 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)
Nov	422,779	413,157	9,622	2.3%	6,811	2,811	410,808	11,971	2.9%	5,972	5,999
Dec	607,067	580,052	27,015	4.7%	7,655	19,359	611,222	-4,155	-0.7%	6,985	-11,140
Jan	742,131	779,510	-37,379	-4.8%	17,904	-55,283	753,753	-11,622	-1.5%	17,557	-29,179
Feb	724,912	741,305	-16,394	-2.2%	15,937	-32,331	697,722	27,190	3.9%	16,581	10,609
Mar	665,183	679,045	-13,862	-2.0%	12,525	-26,387	631,836	33,346	5.3%	15,944	17,402
Apr	570,861	507,411	63,450	12.5%	13,146	50,304	501,966	68,896	13.7%	17,105	51,790
May	378,316	354,226	24,090	6.8%	10,291	13,799	322,485	55,831	17.3%	11,276	44,554
Jun	306,133	280,465	25,668	9.2%	8,458	17,209	256,547	49,586	19.3%	8,753	40,833
Jul	265,414	259,872	5,542	2.1%	5,807	-265	234,159	31,255	13.3%	9,794	21,461
Aug	250,552	245,173	5,379	2.2%	5,451	-72	251,914	-1,362	-0.5%	11,114	-12,476
Sep	266,286	260,772	5,514	2.1%	5,817	-303	259,511	6,775	2.6%	10,303	-3,528
Oct	314,870	308,568	6,303	2.0%	6,857	-554	320,320	-5,450	-1.7%	13,806	-19,256
Peak	3,732,932	3,700,480	32,453	0.9%	73,132	-40,679	3,607,306	125,626	3.5%	79,570	46,056
Off-Peak	1,781,570	1,709,076	72,495	4.2%	42,236	30,259	1,644,935	136,635	8.3%	65,176	71,460
Annual	5,514,503	5,409,555	104,947	1.9%	120,287	-15,340	5,252,242	262,261	5.0%	161,665	100,596

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						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	6,351	6,248	103	1.6%	6,260	91	1.5%
Dec	6,372	6,289	83	1.3%	6,300	72	1.1%
Jan	6,458	6,313	145	2.3%	6,311	147	2.3%
Feb	6,462	6,326	136	2.1%	6,312	150	2.4%
Mar	6,460	6,343	117	1.8%	6,301	159	2.5%
Apr	6,494	6,330	164	2.6%	6,280	214	3.4%
May	6,482	6,299	183	2.9%	6,263	219	3.5%
Jun	6,456	6,267	189	3.0%	6,243	213	3.4%
Jul	6,451	6,310	141	2.2%	6,192	259	4.2%
Aug	6,437	6,297	140	2.2%	6,165	272	4.4%
Sep	6,416	6,276	140	2.2%	6,171	245	4.0%
Oct	6,486	6,345	141	2.2%	6,218	268	4.3%
Peak	6,433	6,308	125	2.0%	6,294	139	2.2%
Off-Peak	6,455	6,299	156	2.5%	6,209	246	4.0%
Annual	6,444	6,304	140	2.2%	6,251	192	3.1%

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

	Total Division Use Per Meter						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	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)
Nov	66.57	66.13	0.44	0.7%	65.62	0.94	1.4%
Dec	95.27	92.23	3.04	3.3%	97.02	-1.75	-1.8%
Jan	114.92	123.48	-8.56	-6.9%	119.43	-4.52	-3.8%
Feb	112.18	117.18	-5.00	-4.3%	110.54	1.64	1.5%
Mar	102.97	107.05	-4.08	-3.8%	100.28	2.69	2.7%
Apr	87.91	80.16	7.75	9.7%	79.93	7.98	10.0%
May	58.36	56.24	2.13	3.8%	51.49	6.87	13.3%
Jun	47.42	44.75	2.67	6.0%	41.09	6.32	15.4%
Jul	41.14	41.18	-0.04	-0.1%	37.82	3.33	8.8%
Aug	38.92	38.93	-0.01	0.0%	40.86	-1.94	-4.7%
Sep	41.50	41.55	-0.05	-0.1%	42.05	-0.55	-1.3%
Oct	48.55	48.63	-0.09	-0.2%	51.51	-2.97	-5.8%
Peak	580.29	586.62	-6.32	-1.1%	573.13	6.99	1.2%
Off-Peak	276.01	271.32	4.69	1.7%	264.94	11.07	4.2%
Annual	855.79	858.17	-2.38	-0.3%	840.18	18.06	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
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
Nov-11	2,727	170,374	81,405	13,692	68,848	18,308	9,989	743	0	366,085
Dec-11	4,027	251,533	120,184	20,214	101,644	27,029	14,747	865	0	540,243
Jan-12	4,601	287,422	137,332	23,098	116,147	30,885	16,851	1,042	0	617,378
Feb-12	4,035	252,044	120,428	20,255	101,851	27,083	14,777	1,012	0	541,485
Mar-12	3,579	223,546	106,811	17,965	90,335	24,021	13,106	912	0	480,275
Apr-12	2,353	146,979	70,227	11,812	59,394	15,794	8,617	805	0	315,980
May-12	2,197	59,838	17,051	13,299	21,192	17,784	2,614	674	0	134,649
Jun-12	1,766	48,104	13,707	10,692	17,037	14,297	2,101	632	0	108,336
Jul-12	1,724	46,957	13,380	10,437	16,630	13,956	2,051	594	0	105,728
Aug-12	1,754	47,780	13,615	10,619	16,922	14,200	2,087	595	0	107,572
Sep-12	1,902	51,802	14,761	11,513	18,346	15,396	2,263	597	0	116,580
Oct-12	2,840	77,338	22,038	17,189	27,390	22,985	3,378	633	0	173,792
Peak	21,321	1,331,896	636,387	107,036	538,218	143,120	78,088	5,380	0	2,861,446
Off-Peak	12,184	331,818	94,552	73,750	117,518	98,617	14,493	3,726	0	746,657
Total	33,505	1,663,715	730,939	180,786	655,736	241,737	92,581	9,106	0	3,608,103

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
Nov-11	2,727	170,374	93,963	18,212	123,409	32,059	49,530	102,807	78,494	671,576
Dec-11	4,027	251,533	138,724	26,887	182,196	47,331	73,124	120,168	83,456	927,446
Jan-12	4,601	287,422	158,517	30,724	208,192	54,084	83,557	132,597	84,256	1,043,951
Feb-12	4,035	252,044	139,006	26,942	182,566	47,427	73,272	128,888	83,586	937,765
Mar-12	3,579	223,546	123,289	23,896	161,924	42,065	64,988	125,252	93,254	861,790
Apr-12	2,353	146,979	81,061	15,711	106,463	27,657	42,729	129,621	91,048	643,621
May-12	2,197	59,838	21,788	17,726	41,357	31,514	20,848	103,281	85,509	384,058
Jun-12	1,766	48,104	17,515	14,250	33,248	25,334	16,760	90,203	86,296	333,477
Jul-12	1,724	46,957	17,098	13,910	32,454	24,730	16,360	79,463	87,840	320,536
Aug-12	1,754	47,780	17,397	14,154	33,023	25,163	16,647	75,169	87,684	318,773
Sep-12	1,902	51,802	18,862	15,346	35,803	27,282	18,048	83,526	83,243	335,813
Oct-12	2,840	77,338	28,160	22,911	53,453	40,731	26,946	95,219	85,317	432,915
Peak	21,321	1,331,896	734,560	142,371	964,750	250,624	387,200	739,333	514,094	5,086,150
Off-Peak	12,184	331,818	120,820	98,298	229,338	174,754	115,610	526,861	515,889	2,125,572
Total	33,505	1,663,715	855,380	240,670	1,194,088	425,378	502,811	1,266,193	1,029,983	7,211,722

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-11	100%	100%	87%	75%	56%	57%	20%	1%	0%	55%
Dec-11	100%	100%	87%	75%	56%	57%	20%	1%	0%	58%
Jan-12	100%	100%	87%	75%	56%	57%	20%	1%	0%	59%
Feb-12	100%	100%	87%	75%	56%	57%	20%	1%	0%	58%
Mar-12	100%	100%	87%	75%	56%	57%	20%	1%	0%	56%
Apr-12	100%	100%	87%	75%	56%	57%	20%	1%	0%	49%
May-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%
Jun-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	32%
Jul-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	33%
Aug-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	34%
Sep-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%
Oct-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	40%
Peak	100%	100%	87%	75%	56%	57%	20%	1%	0%	56%
Off-Peak	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%
Total	100%	100%	85%	75%	55%	57%	18%	1%	0%	50%

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
Nov-11	2,597	110,874	37,725	14,048	43,533	18,967	7,549	743	0	236,036
Dec-11	3,270	191,389	85,840	17,535	81,326	23,537	11,011	865	0	414,773
Jan-12	4,330	278,439	148,074	21,316	122,033	28,480	17,980	1,042	0	621,694
Feb-12	4,292	293,812	152,168	20,364	118,996	27,082	17,145	1,012	0	634,871
Mar-12	3,903	247,682	125,001	18,098	99,734	24,121	14,373	912	0	533,824
Apr-12	2,929	209,701	87,579	15,676	72,597	20,933	10,029	805	0	420,248
May-12	2,382	112,759	40,530	13,253	35,341	17,702	4,827	674	0	227,468
Jun-12	2,444	67,629	17,831	12,577	25,382	16,807	1,680	632	0	144,983
Jul-12	1,759	38,202	8,193	11,791	12,456	15,769	1,596	594	0	90,361
Aug-12	1,844	30,648	6,959	11,781	10,895	15,762	1,433	595	0	79,918
Sep-12	1,817	33,805	7,985	11,818	12,771	15,812	2,072	597	0	86,677
Oct-12	1,937	48,775	13,054	12,529	20,673	16,765	2,885	633	0	117,250
Peak	21,321	1,331,896	636,387	107,036	538,218	143,120	78,088	5,380	0	2,861,446
Off-Peak	12,184	331,818	94,552	73,750	117,518	98,617	14,493	3,726	0	746,657
Total	33,505	1,663,715	730,939	180,786	655,736	241,737	92,581	9,106	0	3,608,103

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
Nov-11	2,597	110,874	48,649	19,032	92,488	33,803	47,506	102,807	78,494	536,250
Dec-11	3,270	191,389	103,581	23,409	156,286	40,989	79,179	120,168	83,456	801,725
Jan-12	4,330	278,439	168,120	27,814	208,767	47,952	72,625	132,597	84,256	1,024,900
Feb-12	4,292	293,812	171,673	26,577	202,453	46,006	65,729	128,888	83,586	1,023,016
Mar-12	3,903	247,682	141,513	23,924	172,348	42,259	66,633	125,252	93,254	916,768
Apr-12	2,929	209,701	101,025	21,616	132,407	39,616	55,528	129,621	91,048	783,491
May-12	2,382	112,759	47,638	18,001	64,799	32,600	26,488	103,281	85,509	493,457
Jun-12	2,444	67,629	22,228	16,744	44,166	29,826	16,670	90,203	86,296	376,206
Jul-12	1,759	38,202	11,682	15,486	27,415	27,247	16,282	79,463	87,840	305,376
Aug-12	1,844	30,648	9,587	15,297	22,091	26,625	14,098	75,169	87,684	283,044
Sep-12	1,817	33,805	11,461	15,747	27,234	27,901	17,174	83,526	83,243	301,907
Oct-12	1,937	48,775	18,224	17,023	43,634	30,554	24,899	95,219	85,317	365,582
Peak	21,321	1,331,896	734,560	142,371	964,750	250,624	387,200	739,333	514,094	5,086,150
Off-Peak	12,184	331,818	120,820	98,298	229,338	174,754	115,610	526,861	515,889	2,125,572
Total	33,505	1,663,715	855,380	240,670	1,194,088	425,378	502,811	1,266,193	1,029,983	7,211,722

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-11	100%	100%	78%	74%	47%	56%	16%	1%	0%	44%
Dec-11	100%	100%	83%	75%	52%	57%	14%	1%	0%	52%
Jan-12	100%	100%	88%	77%	58%	59%	25%	1%	0%	61%
Feb-12	100%	100%	89%	77%	59%	59%	26%	1%	0%	62%
Mar-12	100%	100%	88%	76%	58%	57%	22%	1%	0%	58%
Apr-12	100%	100%	87%	73%	55%	53%	18%	1%	0%	54%
May-12	100%	100%	85%	74%	55%	54%	18%	1%	0%	46%
Jun-12	100%	100%	80%	75%	57%	56%	10%	1%	0%	39%
Jul-12	100%	100%	70%	76%	45%	58%	10%	1%	0%	30%
Aug-12	100%	100%	73%	77%	49%	59%	10%	1%	0%	28%
Sep-12	100%	100%	70%	75%	47%	57%	12%	1%	0%	29%
Oct-12	100%	100%	72%	74%	47%	55%	12%	1%	0%	32%
Peak	100%	100%	87%	75%	56%	57%	20%	1%	0%	56%
Off-Peak	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%
Total	100%	100%	85%	75%	55%	57%	18%	1%	0%	50%

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)
Nov-11	671,576	0.04%	269	236,036	130,049	366,085	366,354	0.87%	3,215	369,569
Dec-11	927,446	0.04%	371	414,773	125,470	540,243	540,614	0.87%	4,745	545,359
Jan-12	1,043,951	0.04%	418	621,694	-4,316	617,378	617,795	0.87%	5,422	623,217
Feb-12	937,765	0.04%	375	634,871	-93,387	541,485	541,860	0.87%	4,756	546,616
Mar-12	861,790	0.04%	345	533,824	-53,549	480,275	480,620	0.87%	4,218	484,838
Apr-12	643,621	0.04%	257	420,248	-104,268	315,980	316,238	0.87%	2,775	319,013
May-12	384,058	0.04%	154	227,468	-92,819	134,649	134,803	0.87%	1,183	135,986
Jun-12	333,477	0.04%	133	144,983	-36,647	108,336	108,469	0.87%	952	109,421
Jul-12	320,536	0.04%	128	90,361	15,367	105,728	105,857	0.87%	929	106,786
Aug-12	318,773	0.04%	128	79,918	27,654	107,572	107,700	0.87%	945	108,645
Sep-12	335,813	0.04%	134	86,677	29,903	116,580	116,714	0.87%	1,025	117,739
Oct-12	432,915	0.04%	173	117,250	56,541	173,792	173,965	0.87%	1,527	175,492
Peak	5,086,150	0.04%	2,034	2,861,446	0	2,861,446	2,863,480	0.87%	25,132	2,888,612
Off-Peak	2,125,572	0.04%	850	746,657	0	746,657	747,508	0.87%	6,561	754,069
Annual	7,211,722	0.04%	2,885	3,608,103	0	3,608,103	3,610,988	0.87%	31,693	3,642,681

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

Base Commodity Costs

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	TOTAL	WINTER
1	**BASE SENDOUT BY CLASS**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
2	**Total Therms**								
3	Res Heat	462,979	478,412	478,412	447,547	478,412	462,979	5,644,196	2,808,740
4	Res General	17,000	17,566	17,566	16,433	17,566	17,000	207,242	103,131
5	G50 Low Annual-Low Winter	102,901	106,331	106,331	99,471	106,331	102,901	1,254,473	624,268
6	G40 Low Annual-High Winter	131,927	136,324	136,324	127,529	136,324	131,927	1,608,324	800,356
7	G51 Med Annual-Low Winter	137,598	142,185	142,185	133,011	142,185	137,598	1,677,463	834,762
8	G41 Med Annual-High Winter	163,970	169,435	169,435	158,504	169,435	163,970	1,998,961	994,750
9	G52 High Annual-Low Winter	5,811	6,005	6,005	5,617	6,005	5,811	70,892	35,254
10	G42 High Annual-High Winter	20,222	20,896	20,896	19,548	20,896	20,222	246,532	122,682
11	Total Firm Sales	1,042,408	1,077,155	1,077,155	1,007,661	1,077,155	1,042,408	12,708,083	6,323,942
12	**% of Total**								
13	Res Heat	44.41%	44.41%	44.41%	44.41%	44.41%	44.41%		
14	Res General	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%		
15	G50 Low Annual-Low Winter	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%		
16	G40 Low Annual-High Winter	12.66%	12.66%	12.66%	12.66%	12.66%	12.66%		
17	G51 Med Annual-Low Winter	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%		
18	G41 Med Annual-High Winter	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%		
19	G52 High Annual-Low Winter	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%		
20	G42 High Annual-High Winter	1.94%	1.94%	1.94%	1.94%	1.94%	1.94%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
23	TOTAL BASE COMMODITY Excld Hedging	$ 505,378	$ 550,611	$ 603,232	$ 584,010	$ 566,779	$ 483,346	$ 3,931,770	$ 3,293,356
24	Res Heat	$ 224,461	$ 244,550	$ 267,922	$ 259,384	$ 251,731	$ 214,675	$ 1,746,269	$ 1,462,724
25	Res General	$ 8,242	$ 8,979	$ 9,837	$ 9,524	$ 9,243	$ 7,882	$ 64,119	$ 53,708
26	G50 Low Annual-Low Winter	$ 49,888	$ 54,354	$ 59,548	$ 57,650	$ 55,950	$ 47,713	$ 388,124	$ 325,103
27	G40 Low Annual-High Winter	$ 63,960	$ 69,685	$ 76,345	$ 73,912	$ 71,731	$ 61,172	$ 497,603	$ 416,806
28	G51 Med Annual-Low Winter	$ 66,710	$ 72,681	$ 79,627	$ 77,089	$ 74,815	$ 63,802	$ 518,994	$ 434,724
29	G41 Med Annual-High Winter	$ 79,495	$ 86,611	$ 94,888	$ 91,864	$ 89,154	$ 76,030	$ 618,463	$ 518,042
30	G52 High Annual-Low Winter	$ 2,817	$ 3,070	$ 3,363	$ 3,256	$ 3,160	$ 2,695	$ 21,923	$ 18,360
31	G42 High Annual-High Winter	$ 9,804	$ 10,682	$ 11,702	$ 11,330	$ 10,995	$ 9,377	$ 76,275	$ 63,890
32									
33	Residential	$ 232,702	$ 253,530	$ 277,759	$ 268,908	$ 260,974	$ 222,558	$ 1,810,388	$ 1,516,432
34	SALES HLF CLASSES	$ 119,416	$ 130,104	$ 142,538	$ 137,996	$ 133,924	$ 114,210	$ 929,041	$ 778,187
35	SALES LLF CLASSES	$ 153,260	$ 166,977	$ 182,935	$ 177,106	$ 171,880	$ 146,579	$ 1,192,340	$ 998,737

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**							**TOTAL**	**WINTER**
37	TOTAL BASE HEDGING COMMODITY	$ 14,846	$ 33,956	$ 66,331	$ 82,537	$ 36,756	$ 11,805	$ 248,647	$ 246,232
38	Res Heat	$ 6,594	$ 15,081	$ 29,461	$ 36,658	$ 16,325	$ 5,243	$ 110,435	$ 109,362
39	Res General	$ 242	$ 554	$ 1,082	$ 1,346	$ 599	$ 193	$ 4,055	$ 4,016
40	G50 Low Annual-Low Winter	$ 1,466	$ 3,352	$ 6,548	$ 8,148	$ 3,628	$ 1,165	$ 24,545	$ 24,307
41	G40 Low Annual-High Winter	$ 1,879	$ 4,297	$ 8,395	$ 10,446	$ 4,652	$ 1,494	$ 31,469	$ 31,163
42	G51 Med Annual-Low Winter	$ 1,960	$ 4,482	$ 8,756	$ 10,895	$ 4,852	$ 1,558	$ 32,821	$ 32,503
43	G41 Med Annual-High Winter	$ 2,335	$ 5,341	$ 10,434	$ 12,983	$ 5,782	$ 1,857	$ 39,112	$ 38,732
44	G52 High Annual-Low Winter	$ 83	$ 189	$ 370	$ 460	$ 205	$ 66	$ 1,386	$ 1,373
45	G42 High Annual-High Winter	$ 288	$ 659	$ 1,287	$ 1,601	$ 713	$ 229	$ 4,824	$ 4,777
46									
47	Residential	$ 6,836	$ 15,635	$ 30,542	$ 38,004	$ 16,925	$ 5,436	$ 114,490	$ 113,378
48	SALES HLF CLASSES	$ 3,508	$ 8,023	$ 15,673	$ 19,503	$ 8,685	$ 2,790	$ 58,753	$ 58,182
49	SALES LLF CLASSES	$ 4,502	$ 10,297	$ 20,115	$ 25,030	$ 11,147	$ 3,580	$ 75,404	$ 74,672

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**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
51	**Total Therms**								
52	Res Heat	1,256,971	2,060,738	2,422,992	2,096,773	1,778,284	1,020,914	11,152,337	10,636,672
53	Res General	10,533	23,080	28,879	24,297	18,559	6,755	131,037	112,103
54	G50 Low Annual-Low Winter	35,320	97,724	126,836	104,999	75,025	16,350	570,865	456,254
55	G40 Low Annual-High Winter	689,874	1,076,895	1,249,981	1,088,160	941,937	577,085	5,770,873	5,623,933
56	G51 Med Annual-Low Winter	47,220	130,661	169,587	140,390	100,310	21,855	763,279	610,023
57	G41 Med Annual-High Winter	531,060	856,633	1,003,019	869,653	742,493	435,670	4,621,158	4,438,529
58	G52 High Annual-Low Winter	1,687	2,732	4,511	4,603	3,206	2,317	21,046	19,055
59	G42 High Annual-High Winter	80,616	127,971	149,210	129,623	111,411	66,777	688,132	665,608
60	Total Firm Sales	2,653,282	4,376,435	5,155,015	4,458,499	3,771,225	2,147,722	23,718,727	22,562,178
61	**% of Total**								
62	Res Heat	47.37%	47.09%	47.00%	47.03%	47.15%	47.53%		
63	Res General	0.40%	0.53%	0.56%	0.54%	0.49%	0.31%		
64	G50 Low Annual-Low Winter	1.33%	2.23%	2.46%	2.36%	1.99%	0.76%		
65	G40 Low Annual-High Winter	26.00%	24.61%	24.25%	24.41%	24.98%	26.87%		
66	G51 Med Annual-Low Winter	1.78%	2.99%	3.29%	3.15%	2.66%	1.02%		
67	G41 Med Annual-High Winter	20.02%	19.57%	19.46%	19.51%	19.69%	20.29%		
68	G52 High Annual-Low Winter	0.06%	0.06%	0.09%	0.10%	0.09%	0.11%		
69	G42 High Annual-High Winter	3.04%	2.92%	2.89%	2.91%	2.95%	3.11%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
72	REMAINING COMMODITY Excld Hedging	$ 1,274,393	$ 2,098,711	$ 2,431,316	$ 2,083,504	$ 1,836,726	$ 999,745	$ 13,688,715	$ 10,724,396
73	Res Heat	$ 603,733	$ 988,223	$ 1,142,782	$ 979,845	$ 866,090	$ 475,226	$ 6,376,461	$ 5,055,900
74	Res General	$ 5,059	$ 11,068	$ 13,621	$ 11,354	$ 9,039	$ 3,144	$ 101,773	$ 53,285
75	G50 Low Annual-Low Winter	$ 16,965	$ 46,863	$ 59,821	$ 49,067	$ 36,540	$ 7,611	$ 510,373	$ 216,867
76	G40 Low Annual-High Winter	$ 331,352	$ 516,423	$ 589,542	$ 508,509	$ 458,758	$ 268,628	$ 3,049,509	$ 2,673,213
77	G51 Med Annual-Low Winter	$ 22,680	$ 62,658	$ 79,984	$ 65,606	$ 48,855	$ 10,173	$ 682,429	$ 289,956
78	G41 Med Annual-High Winter	$ 255,073	$ 410,797	$ 473,065	$ 406,398	$ 361,622	$ 202,801	$ 2,577,448	$ 2,109,755
79	G52 High Annual-Low Winter	$ 810	$ 1,310	$ 2,127	$ 2,151	$ 1,561	$ 1,078	$ 16,659	$ 9,039
80	G42 High Annual-High Winter	$ 38,721	$ 61,368	$ 70,373	$ 60,574	$ 54,261	$ 31,084	$ 374,062	$ 316,382
81									
82	Residential	$ 608,793	$ 999,291	$ 1,156,403	$ 991,199	$ 875,129	$ 478,371	$ 6,478,234	$ 5,109,185
83	SALES HLF CLASSES	$ 40,455	$ 110,832	$ 141,933	$ 116,824	$ 86,956	$ 18,862	$ 1,209,462	$ 515,862
84	SALES LLF CLASSES	$ 625,146	$ 988,588	$ 1,132,981	$ 975,481	$ 874,641	$ 502,512	$ 6,001,019	$ 5,099,349

85	**REMAINING COMMODITY HEDGING COSTS**							**TOTAL**	**WINTER**
86	TOTAL REMAINING COMMODITY HEDGING	$ 31,362	$ 60,714	$ 49,897	$ 37,187	$ 57,299	$ 24,139	$ 274,736	$ 260,598
87	Res Heat	$ 14,857	$ 28,588	$ 23,453	$ 17,489	$ 27,019	$ 11,475	$ 129,186	$ 122,881
88	Res General	$ 125	$ 320	$ 280	$ 203	$ 282	$ 76	$ 1,516	$ 1,285
89	G50 Low Annual-Low Winter	$ 417	$ 1,356	$ 1,228	$ 876	$ 1,140	$ 184	$ 6,602	$ 5,200
90	G40 Low Annual-High Winter	$ 8,154	$ 14,940	$ 12,099	$ 9,076	$ 14,311	$ 6,486	$ 66,863	$ 65,067
91	G51 Med Annual-Low Winter	$ 558	$ 1,813	$ 1,642	$ 1,171	$ 1,524	$ 246	$ 8,827	$ 6,953
92	G41 Med Annual-High Winter	$ 6,277	$ 11,884	$ 9,709	$ 7,254	$ 11,281	$ 4,897	$ 53,534	$ 51,301
93	G52 High Annual-Low Winter	$ 20	$ 38	$ 44	$ 38	$ 49	$ 26	$ 236	$ 215
94	G42 High Annual-High Winter	$ 953	$ 1,775	$ 1,444	$ 1,081	$ 1,693	$ 751	$ 7,972	$ 7,697
95								$ -	$ -
96	Residential	$ 14,982	$ 28,909	$ 23,733	$ 17,691	$ 27,301	$ 11,550	$ 130,702	$ 124,165
97	SALES HLF CLASSES	$ 996	$ 3,206	$ 2,913	$ 2,085	$ 2,713	$ 455	$ 15,664	$ 12,368
98	SALES LLF CLASSES	$ 15,384	$ 28,599	$ 23,252	$ 17,411	$ 27,285	$ 12,133	$ 128,370	$ 124,065

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
63	Res General	LN 53 / LN 60
64	G50 Low Annual-Low Winter	LN 54 / LN 60
65	G40 Low Annual-High Winter	LN 55 / LN 60
66	G51 Med Annual-Low Winter	LN 56 / LN 60
67	G41 Med Annual-High Winter	LN 57 / LN 60
68	G52 High Annual-Low Winter	LN 58 / LN 60
69	G42 High Annual-High Winter	LN 59 / LN 60
70	Total Firm Sales	LN 60 / LN 60

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

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	TOTAL	WINTER
99	**TOTAL COMMODITY COSTS Excluding Hedging**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
100	TOTAL COMMODITY Excld Hedging	$ 1,779,772	$ 2,649,322	$ 3,034,548	$ 2,667,514	$ 2,403,504	$ 1,483,091	$ 17,620,485	$ 14,017,752
101	Res Heat	$ 828,194	$ 1,232,774	$ 1,410,704	$ 1,239,229	$ 1,117,821	$ 689,902	$ 8,122,730	$ 6,518,623
102	Res General	$ 13,301	$ 20,048	$ 23,458	$ 20,878	$ 18,282	$ 11,027	$ 165,893	$ 106,993
103	G50 Low Annual-Low Winter	$ 66,853	$ 101,217	$ 119,369	$ 106,718	$ 92,489	$ 55,324	$ 898,497	$ 541,970
104	G40 Low Annual-High Winter	$ 395,313	$ 586,108	$ 665,887	$ 582,421	$ 530,489	$ 329,800	$ 3,547,112	$ 3,090,018
105	G51 Med Annual-Low Winter	$ 89,390	$ 135,339	$ 159,611	$ 142,695	$ 123,670	$ 73,975	$ 1,201,423	$ 724,680
106	G41 Med Annual-High Winter	$ 334,568	$ 497,407	$ 567,953	$ 498,262	$ 450,775	$ 278,830	$ 3,195,910	$ 2,627,796
107	G52 High Annual-Low Winter	$ 3,628	$ 4,380	$ 5,490	$ 5,407	$ 4,721	$ 3,773	$ 38,583	$ 27,398
108	G42 High Annual-High Winter	$ 48,525	$ 72,050	$ 82,076	$ 71,904	$ 65,257	$ 40,461	$ 450,337	$ 380,272
109									
110	Residential	$ 841,495	$ 1,252,821	$ 1,434,162	$ 1,260,107	$ 1,136,103	$ 700,928	$ 8,288,623	$ 6,625,617
111	SALES HLF CLASSES	$ 159,871	$ 240,935	$ 284,470	$ 254,820	$ 220,880	$ 133,072	$ 2,138,503	$ 1,294,048
112	SALES LLF CLASSES	$ 778,406	$ 1,155,565	$ 1,315,916	$ 1,152,587	$ 1,046,521	$ 649,091	$ 7,193,359	$ 6,098,087
113	**TOTAL HEDGING COMMODITY COSTS**							**TOTAL**	**WINTER**
114	TOTAL HEDGING COMMODITY	$ 46,208	$ 94,670	$ 116,228	$ 119,724	$ 94,055	$ 35,945	$ 523,383	$ 506,830
115	Res Heat	$ 21,451	$ 43,670	$ 52,914	$ 54,147	$ 43,344	$ 16,718	$ 239,621	$ 232,243
116	Res General	$ 367	$ 874	$ 1,361	$ 1,549	$ 881	$ 268	$ 5,571	$ 5,300
117	G50 Low Annual-Low Winter	$ 1,883	$ 4,708	$ 7,776	$ 9,023	$ 4,768	$ 1,349	$ 31,147	$ 29,507
118	G40 Low Annual-High Winter	$ 10,033	$ 19,237	$ 20,494	$ 19,522	$ 18,963	$ 7,980	$ 98,332	$ 96,230
119	G51 Med Annual-Low Winter	$ 2,518	$ 6,295	$ 10,397	$ 12,066	$ 6,376	$ 1,804	$ 41,648	$ 39,456
120	G41 Med Annual-High Winter	$ 8,612	$ 17,225	$ 20,142	$ 20,236	$ 17,063	$ 6,754	$ 92,646	$ 90,033
121	G52 High Annual-Low Winter	$ 103	$ 227	$ 413	$ 499	$ 254	$ 92	$ 1,622	$ 1,587
122	G42 High Annual-High Winter	$ 1,241	$ 2,434	$ 2,731	$ 2,682	$ 2,406	$ 980	$ 12,796	$ 12,474
123									
124	Residential	$ 21,818	$ 44,544	$ 54,275	$ 55,695	$ 44,225	$ 16,986	$ 245,192	$ 237,543
125	SALES HLF CLASSES	$ 4,504	$ 11,230	$ 18,586	$ 21,588	$ 11,398	$ 3,245	$ 74,417	$ 70,550
126	SALES LLF CLASSES	$ 19,887	$ 38,896	$ 43,367	$ 42,441	$ 38,432	$ 15,713	$ 203,774	$ 198,737
127	TOTAL COMMODITY	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
128	Res Heat	$ 849,645	$ 1,276,443	$ 1,463,617	$ 1,293,376	$ 1,161,165	$ 706,619	$ 8,362,351	$ 6,750,867
129	Res General	$ 13,668	$ 20,921	$ 24,819	$ 22,427	$ 19,163	$ 11,295	$ 171,464	$ 112,294
130	G50 Low Annual-Low Winter	$ 68,736	$ 105,925	$ 127,145	$ 115,741	$ 97,258	$ 56,673	$ 929,644	$ 571,477
131	G40 Low Annual-High Winter	$ 405,346	$ 605,345	$ 686,381	$ 601,943	$ 549,453	$ 337,780	$ 3,645,444	$ 3,186,248
132	G51 Med Annual-Low Winter	$ 91,908	$ 141,634	$ 170,008	$ 154,761	$ 130,045	$ 75,779	$ 1,243,071	$ 764,136
133	G41 Med Annual-High Winter	$ 343,181	$ 514,632	$ 588,095	$ 518,499	$ 467,838	$ 285,584	$ 3,288,556	$ 2,717,829
134	G52 High Annual-Low Winter	$ 3,730	$ 4,607	$ 5,904	$ 5,905	$ 4,975	$ 3,865	$ 40,205	$ 28,986
135	G42 High Annual-High Winter	$ 49,766	$ 74,484	$ 84,807	$ 74,586	$ 67,663	$ 41,440	$ 463,133	$ 392,746
136	Total Firm Sales	$ 1,825,980	$ 2,743,992	$ 3,150,777	$ 2,787,238	$ 2,497,559	$ 1,519,036	$ 18,143,868	$ 14,524,582
137									
138	Residential	$ 863,313	$ 1,297,365	$ 1,488,437	$ 1,315,803	$ 1,180,328	$ 717,914	$ 8,533,815	$ 6,863,160
139	SALES HLF CLASSES	$ 164,374	$ 252,165	$ 303,057	$ 276,408	$ 232,278	$ 136,317	$ 2,212,920	$ 1,364,598
140	SALES LLF CLASSES	$ 798,293	$ 1,194,462	$ 1,359,283	$ 1,195,028	$ 1,084,953	$ 664,805	$ 7,397,133	$ 6,296,823
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								17.81%
144	SALES LLF CLASSES								82.19%

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 11A, 11B, 11C, and 11D

Northern Utilities, Inc.

Northern Utilities, Inc. Normal Weather - Sales Service Only 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 Supplies							
Chicago	65,773	0	20,052	3,945	9,932	89,219	188,922
Lewiston Baseload	165,000	170,500	170,500	159,500	170,500	75,000	911,000
PNGTS	29,895	30,892	30,892	28,899	30,892	29,895	181,363
Niagara	0	0	5,095	0	366	5,732	11,194
Tennessee Production	301,628	315,471	132,621	83,816	313,893	348,124	1,495,554
Subtotal Pipeline	562,297	516,862	359,160	276,160	525,583	547,971	2,788,033
Underground Storage							
Tennessee Storage	0	12,175	63,645	59,538	63,205	0	198,563
Tenn Zone 4 Spot	55,432	51,469	0	0	66	61,377	168,345
Tennesse Storage Path	55,432	63,644	63,645	59,538	63,271	61,377	366,907
Washington 10 Storage	84,573	450,172	759,655	695,743	334,372	0	2,324,515
W10 AMA Spot	0	0	0	0	0	0	0
W10 Storage Path	84,573	450,172	759,655	695,743	334,372	0	2,324,515
Subtotal Storage	140,005	513,816	823,299	755,281	397,643	61,377	2,691,422
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
LNG	1,350	1,395	3,453	1,305	1,395	3,120	12,018
Subtotal Peaking	1,350	1,395	3,453	1,305	1,395	3,120	12,018
Total Delivered (Dth)	703,652	1,032,074	1,185,912	1,032,746	924,621	612,468	5,491,472

Northern Utilities, Inc.
Design Weather - Includes all Capacity Assigned Customers
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 Supplies							
Chicago	151,954	180,878	148,748	128,331	163,485	157,835	931,231
Lewiston Baseload	165,000	170,500	170,500	159,500	170,500	75,000	911,000
PNGTS	29,895	30,892	30,892	28,899	30,892	29,895	181,363
Niagara	0	11,593	66,574	46,963	37,948	60,587	223,666
Tennessee Production	392,770	405,862	405,862	379,678	405,862	392,770	2,382,804
Subtotal Pipeline	739,618	799,725	822,576	743,370	808,688	716,087	4,630,064
Underground Storage							
Tennessee Storage	0	15,677	81,953	76,665	81,387	0	255,682
Tenn Zone 4 Spot	76,745	66,275	0	0	566	76,872	220,458
Tennesse Storage Path	76,745	81,953	81,953	76,665	81,953	76,872	476,140
Washington 10 Storage	0	638,684	960,772	879,986	603,882	203,848	3,287,172
W10 AMA Spot	135,967	0	0	0	107,456	0	243,423
W10 Storage Path	135,967	638,684	960,772	879,986	711,338	203,848	3,530,595
Subtotal Storage	212,712	720,637	1,042,725	956,652	793,290	280,720	4,006,736
Peaking Supplies							
Peaking Supply 1	0	0	48,845	980	0	0	49,825
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	94,633	0	0	0	94,633
LNG	1,350	16,259	17,384	67,147	8,334	5,517	115,992
Subtotal Peaking	1,350	16,259	160,863	68,127	8,334	5,517	260,451
Total Delivered (Dth)	953,681	1,536,620	2,026,164	1,768,149	1,610,312	1,002,324	8,897,250

Northern Utilities, Inc. Normal Weather - Sales Service Only Capacity Utilization by Supply Source November 2011 through April 2012			
Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Chicago	188,922	1,074,699	18%
Lewiston Baseload	911,000	911,000	100%
PNGTS	181,363	183,070	99%
Niagara	11,194	522,050	2%
Tennessee Production	1,495,554	2,189,653	68%
Subtotal Pipeline	2,788,033	4,880,472	57%
Underground Storage			
Tennessee Storage	198,563		
Tenn Zone 4 Spot	168,345		
Tennesse Storage Path	366,907	441,768	83%
Washington 10 Storage	2,324,515		
W10 AMA Spot			
W10 Storage Path	2,324,515	4,588,835	51%
Subtotal Storage	2,691,422	5,030,603	54%
Peaking Supplies			
Peaking Supply 1		44,701	0%
Peaking Supply 2		44,701	0%
Peaking Supply 3		976,279	0%
LNG	12,018	112,146	11%
Subtotal Peaking	12,018	1,177,828	1%
Total Delivered (Dth)	5,491,472	11,088,903	50%

Northern Utilities, Inc.
Design Weather - Includes all Capacity Assigned Customers
Capacity Utilization by Supply Source
November 2011 through April 2012

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Chicago	931,231	1,170,988	80%
Lewiston Baseload	911,000	911,000	100%
PNGTS	181,363	199,472	91%
Niagara	223,666	568,824	39%
Tennessee Production	2,382,804	2,385,838	100%
Subtotal Pipeline	4,630,064	5,236,122	88%
Underground Storage			
Tennessee Storage	255,682		
Tenn Zone 4 Spot	220,458		
Tennesse Storage Path	476,140	481,208	99%
Washington 10 Storage	3,287,172		
W10 AMA Spot	243,423		
W10 Storage Path	3,530,595	4,998,520	71%
Subtotal Storage	4,006,736	5,479,728	73%
Peaking Supplies			
Peaking Supply 1	49,825	49,825	100%
Peaking Supply 2	0	49,825	0%
Peaking Supply 3	94,633	1,088,178	9%
LNG	115,992	125,000	93%
Subtotal Peaking	260,451	1,312,828	20%
Total Delivered (Dth)	8,897,250	12,028,678	74%

Northern Utilities Inc.
Forecast of Upcomming Winter Period Design Day Report
2011 / 2012 Winter Period
(Therms)

Demand	
Firm Sales	712,400
Interruptible Sales	0
Capacity Exempt Transportation	338,608
Non-Capacity Exempt Transportation	338,912
Interruptible Transportation	0
Total	1,389,920
Supplies	
Capacity Exempt Transportation	338,608
Pipeline	294,210
Storage	355,290
On-System LNG	100,000
Off-System Peaking	318,880
On-System Propane	0
Total	1,406,988
Effective Degree Day	
New Hampshire	81
Maine	79
Probability	1 in 30

Schedule 12

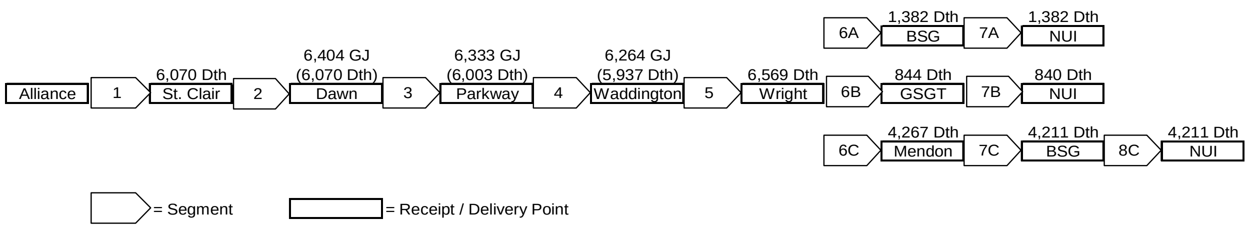
Northern Utilities, Inc.

Northern Capacity by Source of Supply (Dth per Day)		
Supply Source:	Northern Deliverable Winter Capacity (Nov - Mar)	Northern Deliverable Summer Capacity (Apr-Oct)
Lewiston Baseload Supply	5,500	2,500
Chicago (Interconnection of Alliance and Vector Pipelines)	6,434	6,434
Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)	1,096	1,096
Niagara (Interconnection of TransCanada and Tennessee Pipelines)	3,282	3,282
Tennessee Production Area	13,109	13,109
Washington 10 Storage	32,885	0
Tennessee Firm Storage - Market Area	2,644	2,644
Peaking Supply 1	9,965	0
Peaking Supply 2	9,965	0
Peaking Supply 3	11,958	0
Lewiston LNG Facility	10,000	10,000
Total Deliverable Capacity	106,838	39,065

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

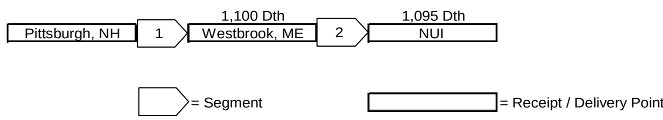


Capacity Path Detail

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	841	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						6,434	Dth				

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

Capacity Path Diagram

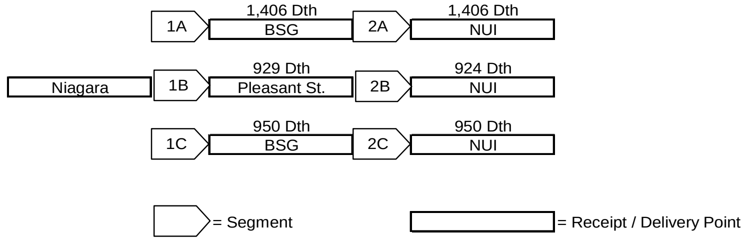


Capacity Path Detail

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	1,096	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						1,096	Dth				

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

Capacity Path Diagram

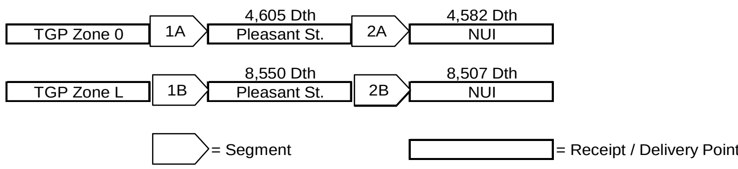


Capacity Path Detail

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	926	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						3,282	Dth				

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

Capacity Path Diagram



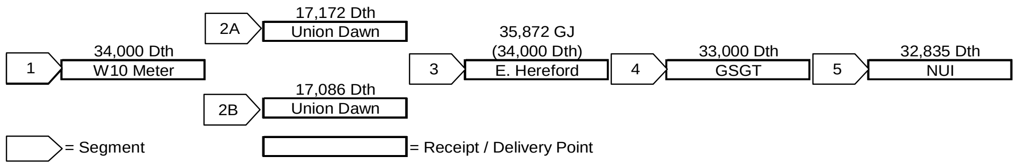
Capacity Path Detail

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	4,589	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	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	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

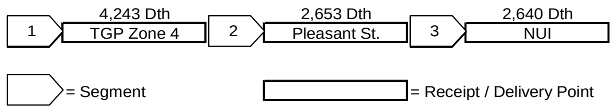
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	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	32,885	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,885	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

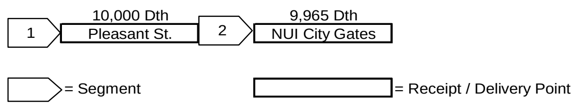
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	10/31/2013	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	10/31/2013	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	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



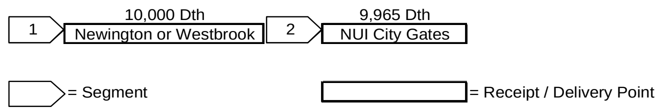
Capacity Path Detail

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	Confidential	NA	NA	3/31/2012	10,000	Dth	Winter Only (Nov - Mar)	NA	Pleasant St.	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	9,965	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						9,965	Dth				

Note 1: Peaking Supply 1 Contract allows Northern to nominate up to 10,000 Dth per Day and up to 50,000 Dth from November 2011 through March 2012.

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

Capacity Path Diagram



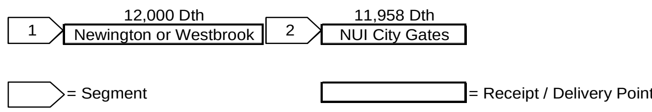
Capacity Path Detail

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	Confidential	NA	NA	3/31/2012	10,000	Dth	Winter Only (Nov-Mar)	NA	Newington, NH or Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	9,965	Dth	Year-Round	Newington, NH or Westbrook, ME	Northern City Gates	
Total Path Deliverable						9,965	Dth				

Note 1: Peaking Supply 2 Contract allows Northern to nominate up to 10,000 Dth per Day and up to 50,000 Dth from November 2011 through March 2012.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Supply 3

Capacity Path Diagram



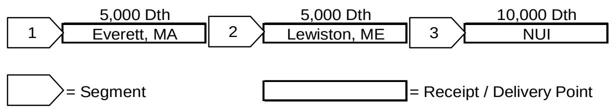
Capacity Path Detail

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	Confidential	NA	NA	2/29/2012	12,000	Dth	Winter Only (Dec-Feb)	NA	Newington, NH or Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2011	11,958	Dth	Year-Round	Newington, NH or Westbrook, ME	Northern City Gates	
Total Path Deliverable						11,958	Dth				

Note 1: Peaking Supply 2 Contract allows Northern to nominate up to 12,000 Dth per Day from December 2011 through February 2012.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Lewiston LNG Plant

Capacity Path Diagram



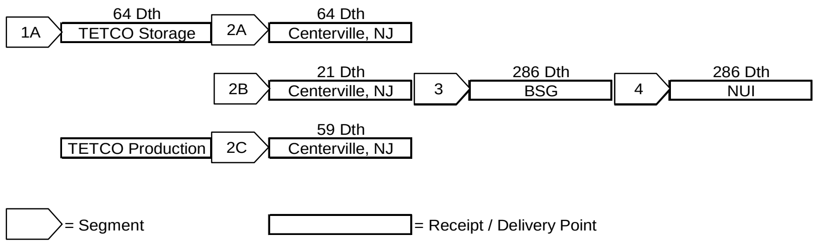
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	LNG Contract	Confidential	NA	NA	10/31/2012	5,000	Dth	Year-Round	NA	Everett, MA	NA
2	LNG Trucking Contract	Confidential			10/31/2012	5,000	Dth	Year-Round	Everett, MA	Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	10,000	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						10,000	Dth				

Note 1: The LNG Contract allows Northern to nominate up to 5,000 Dth per day with an annual maximum take is 125,000 Dth.

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

TETCO M3 → 1 → Lambertville, NJ (965 Dth) → 2 → BSG (965 Dth) → 3 → NUI (965 Dth)

= Segment   = Receipt / Delivery Point

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

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2011 through October 2012

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	730,939	38%	85%
G50	180,786	9%	75%
G41	655,736	34%	55%
G51	241,737	13%	57%
G42	92,581	5%	18%
G52	9,106	0%	1%
Special Contracts	-	0%	0%
Total C&I	1,910,884	100%	35%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
T40	124,440	3%	15%
T50	59,884	2%	25%
T41	538,352	15%	45%
T51	183,641	5%	43%
T42	410,230	11%	82%
T52	1,257,088	35%	99%
Special Contracts	1,029,983	29%	100%
Total C&I	3,603,619	100%	65%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G/T40	855,380	16%
G/T50	240,670	4%
G/T41	1,194,088	22%
G/T51	425,378	8%
G/T42	502,811	9%
G/T52	1,266,193	23%
Special Contracts	1,029,983	19%
Total C&I	5,514,503	100%

Schedule 14

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
Storage Inventory and Activity Costs

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-11	201,401	-	-	201,401	$ 898,283	$ 4.46	NA	$ -	$ 4.46	$ -	$ 898,283	2.19%	$ 1,637	$ 898,283	$ -
Dec-11	201,401	-	12,349	189,052	$ 898,283	$ 4.46	NA	$ -	$ 4.46	$ 55,079	$ 843,204	2.19%	$ 1,586	$ 843,204	$ 55,079
Jan-12	189,052	-	64,554	124,498	$ 843,204	$ 4.46	NA	$ -	$ 4.46	$ 287,923	$ 555,281	2.19%	$ 1,274	$ 555,281	$ 287,923
Feb-12	124,498	-	60,389	64,108	$ 555,281	$ 4.46	NA	$ -	$ 4.46	$ 269,347	$ 285,934	2.19%	$ 766	$ 285,934	$ 269,347
Mar-12	64,108	-	64,108	-	$ 285,934	$ 4.46	NA	$ -	$ 4.46	$ 285,934	$ -	2.19%	$ 260	$ -	$ 285,934
Apr-12	-	-	-	-	$ -	NA	NA	$ -	$ 4.69	$ -	$ -	2.19%	$ -	$ -	$ -
May-12	-	53,599	-	53,599		NA	$ 4.61	$ 247,327	$ 4.61	$ -	$ 247,327	2.19%	$ 225	$ 247,327	$ -
Jun-12	53,599	51,870	-	105,469	$ 247,327	$ 4.61	$ 4.66	$ 241,574	$ 4.64	$ -	$ 488,901	2.19%	$ 671	$ 488,901	$ -
Jul-12	105,469	53,599	-	159,068	$ 488,901	$ 4.64	$ 4.71	$ 252,207	$ 4.66	$ -	$ 741,107	2.19%	$ 1,120	$ 741,107	$ -
Aug-12	159,068	42,333	-	201,401	$ 741,107	$ 4.66	$ 4.73	$ 200,392	$ 4.67	$ -	$ 941,499	2.19%	$ 1,533	$ 941,499	$ -
Sep-12	201,401	-	-	201,401	$ 941,499	$ 4.67	NA	$ -	$ 4.67	$ -	$ 941,499	2.19%	$ 1,715	$ 941,499	$ -
Oct-12	201,401	-	-	201,401	$ 941,499	$ 4.67	NA	$ -	$ 4.67	$ -	$ 941,499	2.19%	$ 1,715	$ 941,499	$ -

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-11	2,640,440	-	86,461	2,553,979	$11,607,374	$ 4.40	NA	$ -	$ 4.40	$ 380,082	$ 11,227,292	2.19%		$ 11,227,292	$ 380,082
Dec-11	2,553,979	-	460,219	2,093,760	$11,227,292	$ 4.40	NA	$ -	$ 4.40	$2,023,124	$ 9,204,167	2.19%		$ 9,204,167	$2,023,124
Jan-12	2,093,760	-	776,610	1,317,150	$ 9,204,167	$ 4.40	NA	$ -	$ 4.40	$3,413,977	$ 5,790,190	2.19%		$ 5,790,190	$3,413,977
Feb-12	1,317,150	-	711,271	605,879	$ 5,790,190	$ 4.40	NA	$ -	$ 4.40	$3,126,748	$ 2,663,443	2.19%		$ 2,663,443	$3,126,748
Mar-12	605,879	-	341,835	264,044	$ 2,663,443	$ 4.40	NA	$ -	$ 4.40	$1,502,705	$ 1,160,737	2.19%		$ 1,160,737	$1,502,705
Apr-12	264,044	391,709	-	655,753	$ 1,160,737	$ 4.40	$ 4.52	$1,770,305	$ 4.47	$ -	$ 2,931,042	2.19%		$ 2,931,042	$ -
May-12	655,753	404,766	-	1,060,520	$ 2,931,042	$ 4.47	$ 4.55	$1,841,201	$ 4.50	$ -	$ 4,772,244	2.19%		$ 4,772,244	$ -
Jun-12	1,060,520	391,709	-	1,452,229	$ 4,772,244	$ 4.50	$ 4.59	$1,798,101	$ 4.52	$ -	$ 6,570,344	2.19%		$ 6,570,344	$ -
Jul-12	1,452,229	404,766	-	1,856,995	$ 6,570,344	$ 4.52	$ 4.64	$1,877,009	$ 4.55	$ -	$ 8,447,353	2.19%		$ 8,447,353	$ -
Aug-12	1,856,995	404,766	-	2,261,761	$ 8,447,353	$ 4.55	$ 4.66	$1,888,197	$ 4.57	$ -	$ 10,335,550	2.19%		$ 10,335,550	$ -
Sep-12	2,261,761	378,679	-	2,640,440	$10,335,550	$ 4.57	$ 4.67	$1,768,464	$ 4.58	$ -	$ 12,104,014	2.19%		$ 12,104,014	$ -
Oct-12	2,640,440	-	-	2,640,440	$12,104,014	$ 4.58	NA	$ -	$ 4.58	$ -	$ 12,104,014	2.19%		$ 12,104,014	$ -

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-11	9,708	1,350	1,350	9,708	$ 64,058	$ 6.60	$ 5.46	$ 7,372	$ 6.46	$ 8,721	$ 62,709	2.19%	$ 115	$ 62,709	$ 8,721
Dec-11	9,708	1,395	1,395	9,708	$ 62,709	$ 6.46	$ 7.04	$ 9,824	$ 6.53	$ 9,114	$ 63,419	2.19%	$ 115	$ 63,419	$ 9,114
Jan-12	9,708	2,482	3,453	8,737	$ 63,419	$ 6.53	$ 8.56	$ 21,237	$ 6.95	$ 23,979	$ 60,678	2.19%	$ 113	$ 60,678	$ 23,979
Feb-12	8,737	1,305	1,305	8,737	$ 60,678	$ 6.95	$ 8.38	$ 10,941	$ 7.13	$ 9,307	$ 62,312	2.19%	$ 112	$ 62,312	$ 9,307
Mar-12	8,737	1,395	1,395	8,737	$ 62,312	$ 7.13	$ 6.26	$ 8,727	$ 7.01	$ 9,781	$ 61,258	2.19%	$ 113	$ 61,258	$ 9,781
Apr-12	8,737	4,091	3,120	9,707	$ 61,258	$ 7.01	$ 5.73	$ 23,436	$ 6.60	$ 20,600	$ 64,094	2.19%	$ 114	$ 64,094	$ 20,600
May-12	9,708	1,395	1,395	9,708	$ 64,094	$ 6.60	$ 5.76	$ 8,032	$ 6.50	$ 9,062	$ 63,064	2.19%	$ 116	$ 63,064	$ 9,062
Jun-12	9,708	1,350	1,350	9,708	$ 63,064	$ 6.50	$ 5.80	$ 7,829	$ 6.41	$ 8,655	$ 62,237	2.19%	$ 114	$ 62,237	$ 8,655
Jul-12	9,708	1,395	1,395	9,708	$ 62,237	$ 6.41	$ 5.84	$ 8,154	$ 6.34	$ 8,844	$ 61,547	2.19%	$ 113	$ 61,547	$ 8,844
Aug-12	9,708	1,395	1,395	9,708	$ 61,547	$ 6.34	$ 5.87	$ 8,191	$ 6.28	$ 8,762	$ 60,976	2.19%	$ 112	$ 60,976	$ 8,762
Sep-12	9,708	1,350	1,350	9,708	$ 60,976	$ 6.28	$ 5.88	$ 7,934	$ 6.23	$ 8,413	$ 60,496	2.19%	$ 111	$ 60,496	$ 8,413
Oct-12	9,708	1,395	1,395	9,708	$ 60,496	$ 6.23	$ 5.91	$ 8,240	$ 6.19	$ 8,637	$ 60,100	2.19%	$ 110	$ 60,100	$ 8,637

Schedule 15

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
May 2010 - April 2011

	AMOUNT	
Winter Period Beg. Balance	$2,527,403	SCHEDULE 2
Less: Reported Collections	($32,736,593)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$31,043,868	SCHEDULE 4
Add: Interest	$138,949	SCHEDULE 2
Winter Period Ending Balance	$973,628	

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED WINTER PERIOD ACCOUNTS
May 2010 - April 2011
Acct 191.20

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
WINTER PERIOD													
Winter Period Account Beginning Balance	$ 2,527,403	$ 2,960,839	$ 3,830,779	$ 4,148,747	$ 4,817,957	$ 5,378,433	$ 5,928,076	$ 6,528,993	$ 6,435,669	$ 4,898,490	$ 3,305,320	$ 1,390,024	$ 2,527,403
Plus: Cost of Firm Gas (Schedule 4)	$ 426,013	$ 857,257	$ 308,045	$ 655,977	$ 545,138	$ 533,511	$ 3,164,233	$ 5,445,662	$ 6,473,214	$ 5,246,244	$ 5,006,539	$ 2,382,035	$ 31,043,868
Less: Reported Collections (Schedule 3)	$ 0	$ 3,499	$ (869)	$ 1,107	$ 1,549	$ 842	$ (2,580,162)	$ (5,556,519)	$ (8,025,720)	$ (6,850,509)	$ (6,928,185)	$ (2,801,628)	$ (32,736,593)
Less: Billing Adjustment													
Winter Period Account Ending Balance	$ 2,953,417	$ 3,821,595	$ 4,137,956	$ 4,805,831	$ 5,364,644	$ 5,912,785	$ 6,512,147	$ 6,418,136	$ 4,883,163	$ 3,294,226	$ 1,383,674	$ 970,432	$ 834,679
Month's Average Balance	$ 2,740,410	$ 3,391,217	$ 3,984,367	$ 4,477,289	$ 5,091,300	$ 5,645,609	$ 6,220,111	$ 6,473,565	$ 5,659,416	$ 4,096,358	$ 2,344,497	$ 1,180,228	
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	$ 7,422	$ 9,185	$ 10,791	$ 12,126	$ 13,789	$ 15,290	$ 16,846	$ 17,533	$ 15,328	$ 11,094	$ 6,350	$ 3,196	$ 138,949
Winter Period Account Ending Balance w/int	$ 2,960,839	$ 3,830,779	$ 4,148,747	$ 4,817,957	$ 5,378,433	$ 5,928,076	$ 6,528,993	$ 6,435,669	$ 4,898,490	$ 3,305,320	$ 1,390,024	$ 973,628	$ 973,628

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2010 - April 2011

FORM III
Schedule 3

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Accrued Revenue	$ (822,237)	$ -	$ -	$ -	$ -	$ -	$ 1,768,173	$ 1,169,565	$ 1,127,732	$ (813,839)	$ 756,635	$ (1,767,915)	$ 1,418,115
Billed Revenue	$ 822,236	$ (3,499)	$ 869	$ (1,107)	$ (1,549)	$ (842)	$ 811,989	$ 4,386,954	$ 6,897,988	$ 7,664,347	$ 6,171,550	$ 4,569,542	$ 31,318,478
Calendarized Revenue	**$ (0)**	**$ (3,499)**	**$ 869**	**$ (1,107)**	**$ (1,549)**	**$ (842)**	**$ 2,580,162**	**$ 5,556,519**	**$ 8,025,720**	**$ 6,850,509**	**$ 6,928,185**	**$ 2,801,628**	**$ 32,736,593**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2010 - April 2011

Commodity Costs:	May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Actual)	Sep-10 (Actual)	Oct-10 (Actual)	Nov-10 (Actual)	Dec-10 (Actual)	Jan-11 (Actual)	Feb-11 (Actual)	Mar-11 (Actual)	Apr-11 (Actual)	Total Winter
BG Energy Merchants, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 711,103	$ 514,493	$ 474,328	$ 470,883	**$ 2,170,806**
Distrigas of Massachusetts, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 101,484	$ 228,317	$ 260,990	$ 283,826	$ 260,545	**$ 1,135,162**
Emera Energy Services, Inc.	$ 279,072	$ 3,925	$ -	$ -	$ -	$ -	$ -	$ 65,357	$ 385,878	$ 417,401	$ 420,810	$ 178,742	**$ 1,751,185**
FPL Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,074	$ 234,196	$ 98,827	$ -	**$ 371,097**
JP Morgan Ventures Energy Corp	$ 349,226	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 349,226**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,057	$ 206,923	$ -	$ -	$ -	**$ 217,980**
Macquarie Cook Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,713	$ -	$ -	$ -	$ -	**$ 37,713**
National Energy & Trade	$ 174,613	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,518	$ 118,375	$ 76,393	$ 23,281	**$ 448,180**
Portland Natural Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,176	$ -	$ 697	**$ 4,873**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 96,553	$ 227,153	$ 63,760	**$ 387,466**
South Jersey Resources	$ 11,649	$ -	$ -	$ -	$ -	$ -	$ 11,402	$ -	$ -	$ -	$ -	$ 5,906	**$ 28,957**
Spark Energy Gas, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 148,819	$ -	$ 361,732	$ -	$ 393,903	**$ 904,454**
Sprague Energy Corp.	$ 90,521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 90,521**
Tennessee Gas Pipeline Co	$ 1,897	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,336	$ 5,849	$ 4,192	$ 2,121	$ 3,126	**$ 18,521**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 201,699	$ 43,648	**$ 245,347**
Misc	$ -	$ -	$ -	$ -	$ (1,983)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,983)**
Subtotal	$ 906,977	$ 3,925	$ -	$ -	$ (1,983)	$ -	$ 11,402	$ 365,766	$ 1,631,662	$ 2,012,108	$ 1,785,157	$ 1,444,491	**$ 8,159,504**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 739,132	$ 1,657,574	$ 2,165,594	$ 1,717,909	$ 1,448,855	$ 1,209,861	**$ 8,938,925**
Commodity Cost Reversals	$ (908,200)	$ -	$ -	$ -	$ -	$ -	$ -	$ (739,132)	$ (1,657,574)	$ (2,165,594)	$ (1,717,909)	$ (1,448,855)	**$ (8,637,264)**
Subtotal	$ (1,223)	$ 3,925	$ -	$ -	$ (1,983)	$ -	$ 750,534	$ 1,284,207	$ 2,139,682	$ 1,564,423	$ 1,516,103	$ 1,205,497	**$ 8,461,165**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 982,785	$ 2,454,160	$ 2,544,470	$ 1,576,288	$ 1,213,681	$ 870	**$ 8,772,254**
ATV		$ -					$ (30,606)	$ 72,894	$ 111,901	$ 85,224	$ 102,352	$ 22,329	**$ 364,093**
Non Traditional Sales	$ (425,015)	$ -	$ -	$ -	$ -	$ -	$ (4,520)	$ (2,316)	$ (848,206)	$ (141,454)	$ (129,906)	$ (27,350)	**$ (1,578,766)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,250	$ 1,739	$ 11,720	$ 31,076	$ (188)	$ 7,938	**$ 62,534**
Company Managed	$ (20,480)	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,309)	$ (341,851)	$ (402,896)	$ (336,167)	$ (246,181)	**$ (1,381,885)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,008	$ 6,370	$ 7,304	$ 1,225	$ 3,279	$ 4,889	**$ 27,075**
Transportation Charges	$ 47,189	$ 160,076	$ (213,177)	$ 117,743	$ -	$ -	$ -	$ 3,498	$ 95,263	$ 28,758	$ 92,402	$ 69,554	**$ 401,304**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,625	$ 404,041	$ 147,924	$ 167,138	$ 198,755	$ 212,179	**$ 1,247,662**
Inventory Finance Charges	$ 404	$ 579	$ 774	$ 957	$ 1,048	$ 1,087	$ 1,095	$ 1,060	$ 727	$ 355	$ 183	$ 46	**$ 8,312**
Subtotal	$ (397,903)	$ 160,654	$ (212,403)	$ 118,699	$ 1,048	$ 1,087	$ 1,080,636	$ 2,907,137	$ 1,729,251	$ 1,345,713	$ 1,144,390	$ 44,273	**$ 7,922,583**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (388,606)	$ (1,181,189)	$ (631,980)	$ (388,103)	$ (273,531)	$ (93,943)	**$ (2,957,352)**
Sales for Resale Reversals	$ 400,495	$ -	$ -	$ -	$ -	$ -	$ -	$ 388,606	$ 1,181,189	$ 631,980	$ 388,103	$ 273,531	**$ 3,263,904**
Subtotal	$ 400,495	$ -	$ -	$ -	$ -	$ -	$ (388,606)	$ (792,583)	$ 549,208	$ 243,877	$ 114,573	$ 179,587	**$ 306,552**
Total Commodity Costs	**$ 1,370**	**$ 164,579**	**$ (212,403)**	**$ 118,699**	**$ (935)**	**$ 1,087**	**$ 1,442,565**	**$ 3,398,761**	**$ 4,418,142**	**$ 3,154,012**	**$ 2,775,065**	**$ 1,429,358**	**$ 16,690,300**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2010 - April 2011

Demand Costs	May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Actual)	Sep-10 (Actual)	Oct-10 (Actual)	Nov-10 (Actual)	Dec-10 (Actual)	Jan-11 (Actual)	Feb-11 (Actual)	Mar-11 (Actual)	Apr-11 (Actual)	Total Winter
Pipeline Reservation													
Algonquin Gas Transmission	$ 15,767	$ 15,770	$ 15,767	$ 15,767	$ 15,767	$ 15,767	$ 15,767	$ 16,159	$ 16,159	$ 16,159	$ 16,159	$ 16,159	**$ 191,172**
BG Energy Merchants, LLC	$ 332,323	$ 344,837	$ 335,961	$ 336,539	$ 342,174	$ 344,671	$ 346,402	$ 351,934	$ 345,595	$ 357,811	$ 366,325	$ 536,412	**$ 4,340,983**
Emera Energy Services, Inc.	$ -	$ 60,549	$ 30,609	$ 30,045	$ 30,979	$ 31,034	$ -	$ 31,046	$ -	$ -	$ -	$ -	**$ 214,262**
Granite State Gas Transmission, Inc.	$ 78,400	$ 78,400	$ 78,412	$ 78,412	$ 78,433	$ 78,414	$ 80,364	$ 80,262	$ 134,845	$ 134,781	$ 134,737	$ 134,695	**$ 1,170,156**
Iroquois Gas Transmision System	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 21,079	$ 21,079	$ 21,079	$ -	$ 42,158	**$ 249,366**
Portland Natural Gas Transmission	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,309	$ 850,338	$ 1,248,914	$ 1,249,025	$ 1,248,914	$ 1,248,914	**$ 5,946,245**
Tennessee Gas Pipeline Co	$ 130,396	$ 130,396	$ 102,900	$ 130,396	$ 130,396	$ 102,900	$ 130,396	$ 133,638	$ 76,183	$ 133,638	$ 133,638	$ 76,183	**$ 1,411,058**
Texas Eastern Transmission		$ 3,261	$ 9,784	$ 3,261	$ 3,254	$ 3,254	$ 3,254	$ 3,335	$ 3,336	$ 3,336	$ 3,305	$ 3,304	**$ 42,686**
Union Gas Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,429	$ 7,228	$ 7,274	$ 7,356	**$ 36,286**
Vector Pipeline LP	$ 85,737	$ 85,734	$ 85,745	$ 85,736	$ 85,752	$ 85,781	$ 85,789	$ 125,834	$ 125,856	$ 125,858	$ 125,858	$ 125,920	**$ 1,229,601**
Total Pipeline Reservation	$ 677,496	$ 753,820	$ 694,050	$ 715,029	$ 721,629	$ 696,694	$ 696,849	$ 1,613,624	$ 1,986,395	$ 2,048,915	$ 2,036,210	$ 2,191,101	**$ 14,831,814**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,022	$ 1,025	$ 1,142	$ 1,351	$ 1,186	$ 1,087	$ 1,104	$ 1,136	$ 1,210	$ -	$ 2,235	$ -	**$ 12,500**
Distrigas of Massachusetts	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 96,998	$ 107,849	$ 107,849	$ 107,849	$ 107,849	**$ 1,222,370**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 187,969	$ 187,969	$ 187,969	$ 187,969	$ 187,969	**$ 939,846**
Total Product Demand	$ 100,162	$ 100,165	$ 100,281	$ 100,491	$ 100,326	$ 100,227	$ 100,244	$ 286,103	$ 297,028	$ 295,818	$ 298,053	$ 295,818	**$ 2,174,716**
Storage Pipeline Transportation and Demand Reservation													
Tennessee Gas Pipeline	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,707	$ 4,707	$ 4,707	$ 4,707	$ 4,707	**$ 55,684**
Washington 10 (BG Energy)	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 117,141	$ 117,141	$ 117,141	$ 117,141	$ 117,141	**$ 1,385,803**
Texas Eastern	$ -	$ 83	$ 249	$ 83	$ 83	$ 83	$ 83	$ 84	$ 84	$ 84	$ 83	$ 84	**$ 1,083**
Company Managed	$ (152,105)	$ (80,108)	$ (76,076)	$ (76,668)	$ (76,162)	$ (79,868)	$ (80,220)	$ (295,491)	$ (360,493)	$ (367,839)	$ (384,681)	$ (418,937)	**$ (2,448,647)**
Total Storage and Demand Reservation	$ (33,212)	$ 38,868	$ 43,065	$ 42,306	$ 42,813	$ 39,107	$ 38,756	$ (173,558)	$ (238,561)	$ (245,907)	$ (262,749)	$ (297,005)	**$ (1,006,077)**
Demand Cost Estimates	$ 668,427	$ 783,265	$ 787,966	$ 781,710	$ 778,004	$ 789,086	$ 1,659,762	$ 1,965,329	$ 1,962,205	$ 1,941,756	$ 2,085,801	$ 854,320	**$ 15,057,632**
Demand Cost Reversals	$ (663,217)	$ (668,427)	$ (783,265)	$ (787,966)	$ (781,710)	$ (778,004)	$ (789,086)	$ (1,659,762)	$ (1,965,329)	$ (1,962,205)	$ (1,941,756)	$ (2,085,801)	**$ (14,866,529)**
Total Fixed Demand	$ 749,655	$ 1,007,690	$ 842,097	$ 851,572	$ 861,062	$ 847,110	$ 1,706,525	$ 2,031,736	$ 2,041,738	$ 2,078,378	$ 2,215,558	$ 958,433	**$ 16,191,555**
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,657	$ 30,657	$ 30,657	$ 30,657	$ 30,657	$ 30,657	**$ 183,943**
Capacity Release	$ (127,117)	$ (129,921)	$ (136,339)	$ (129,346)	$ (129,032)	$ (129,089)	$ (129,330)	$ (99,858)	$ (167,802)	$ (134,599)	$ (132,565)	$ (137,207)	**$ (1,582,206)**
Capacity Mitigation	$ (8,963)	$ (9,007)	$ (8,971)	$ (8,973)	$ (9,005)	$ (9,259)	$ (9,260)	$ (12,186)	$ (12,623)	$ (12,343)	$ (12,501)	$ (12,491)	**$ (125,583)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	**$ 686,673**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	**$ 98,333**
Demand Cost Estimates - Capacity Release	$ (140,258)	$ (140,005)	$ (140,007)	$ (139,645)	$ (140,261)	$ (140,262)	$ (148,021)	$ (182,303)	$ (150,036)	$ (150,730)	$ (151,240)	$ (168,788)	**$ (1,791,556)**
Demand Cost Reversals - Capacity Release	$ 127,663	$ 140,258	$ 140,005	$ 140,007	$ 139,645	$ 140,261	$ 140,262	$ 148,021	$ 182,303	$ 150,036	$ 150,730	$ 151,240	**$ 1,750,431**
Total Demand Costs	**$ 600,980**	**$ 869,015**	**$ 696,785**	**$ 713,615**	**$ 722,410**	**$ 708,761**	**$ 1,721,668**	**$ 2,046,901**	**$ 2,055,072**	**$ 2,092,232**	**$ 2,231,473**	**$ 952,678**	$ 15,411,591
Demand Costs Transferred to Summer Perioc	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,058,022)
Net Demand Costs For Winter Period	**$ 424,643**	**$ 692,678**	**$ 520,448**	**$ 537,278**	**$ 546,073**	**$ 532,424**	**$ 1,721,668**	**$ 2,046,901**	**$ 2,055,072**	**$ 2,092,232**	**$ 2,231,473**	**$ 952,678**	$ 14,353,569
Total Gas Costs	**$ 426,013**	**$ 857,257**	**$ 308,045**	**$ 655,977**	**$ 545,138**	**$ 533,511**	**$ 3,164,233**	**$ 5,445,662**	**$ 6,473,214**	**$ 5,246,244**	**$ 5,006,539**	**$ 2,382,035**	**$ 31,043,868**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2010 - April 2011

New Hampshire	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Throughput IN													
BTU Factor	1.038	1.039	1.033	1.036	1.039	1.041	1.039	1.039	1.046	1.049	1.048	1.041	
GST Meter Throughput (MCF)	312,869	265,598	249,025	269,606	273,645	427,825	569,708	849,169	1,045,428	914,419	780,093	493,361	6,450,746
Salem Meter (MCF)	12,766	9,904	9,385	9,959	10,496	18,586	31,154	57,324	67,178	57,567	45,512	25,940	355,771
GST Meter Throughpurt (DTH)	324,758	275,956	257,243	279,312	284,317	445,366	591,927	882,287	1,093,518	959,226	817,537	513,589	6,725,035
Salem Meter (DTH)	13,251	10,290	9,695	10,318	10,905	19,348	32,369	59,560	70,268	60,388	47,697	27,004	371,092
LNG/Propane													
Total Throughput	338,009	286,247	266,938	289,629	295,222	464,714	624,296	941,846	1,163,786	1,019,613	865,234	540,592	7,096,126
Throughput OUT													
Residential Gas													
Charged	89,805	48,593	37,542	31,398	35,343	45,287	107,248	195,796	291,469	327,102	254,646	192,084	1,656,313
Uncharged Current	24,753	17,120	17,902	18,960	24,555	50,075	80,135	148,473	168,349	135,111	164,902	93,513	943,847
Uncharged Prior	-71,183	-24,753	-17,120	-17,902	-18,960	-24,555	-50,075	-80,135	-148,473	-168,349	-135,111	-164,902	-921,517
Total Residential Gas	**43,375**	**40,960**	**38,324**	**32,457**	**40,938**	**70,806**	**137,308**	**264,134**	**311,345**	**293,864**	**284,436**	**120,695**	1,678,643
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	100,468	56,259	50,821	48,982	52,749	63,675	121,973	208,217	342,640	350,674	278,007	203,456	1,877,921
Uncharged Current	33,010	24,405	24,409	28,929	31,853	48,382	82,007	151,318	195,063	145,510	181,239	100,855	1,046,979
Uncharged Prior	-75,149	-33,010	-24,405	-24,409	-28,929	-31,853	-48,382	-82,007	-151,318	-195,063	-145,510	-181,239	-1,021,274
Total C/I Gas	**58,329**	**47,654**	**50,825**	**53,502**	**55,673**	**80,204**	**155,597**	**277,528**	**386,386**	**301,121**	**313,736**	**123,071**	1,903,627
Transportation													
Charged	210,279	200,287	183,338	202,932	206,761	246,364	292,350	379,482	438,660	419,294	396,434	311,797	3,487,978
Uncharged Current	55,335	55,311	49,937	65,560	74,219	115,721	133,472	208,493	192,682	145,148	206,752	127,983	1,430,613
Uncharged Prior	-85,504	-55,335	-55,311	-49,937	-65,560	-74,219	-115,721	-133,472	-208,493	-192,682	-145,148	-206,752	-1,388,134
Total Transportation	**180,110**	**200,263**	**177,964**	**218,555**	**215,420**	**287,866**	**310,101**	**454,503**	**422,849**	**371,760**	**458,038**	**233,029**	**3,530,457**
Company Use	**25**	**7**	**2**	**2**	**6**	**17**	**37**	**85**	**145**	**141**	**104**	**76**	**647**
Total Throughput OUT	**281,838**	**288,884**	**267,115**	**304,515**	**312,038**	**438,894**	**603,044**	**996,250**	**1,120,725**	**966,886**	**1,056,314**	**476,871**	**7,113,374**
Total Throughput IN	**338,009**	**286,247**	**266,938**	**289,629**	**295,222**	**464,714**	**624,296**	**941,846**	**1,163,786**	**1,019,613**	**865,234**	**540,592**	**7,096,126**
Difference IN/OUT	56,171	-2,638	-178	-14,886	-16,815	25,820	21,252	-54,404	43,061	52,727	-191,080	63,721	-17,248
%													-0.24%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2011

PEAK PERIOD - Acct 182.11

		BEGINNING BALANCE	WORKING CAP ALLOWANCE(1)	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
May 2010	$	(83,068)	240	0.0564%	553	794	(82,274)	(82,671)	3.25%	(224)	(82,498)
June	$	(82,498)	483	0.0564%	13	497	(82,001)	(82,250)	3.25%	(223)	(82,224)
July	$	(82,224)	174	0.0564%	(2)	171	(82,053)	(82,138)	3.25%	(222)	(82,275)
August	$	(82,275)	370	0.0564%	2	372	(81,903)	(82,089)	3.25%	(222)	(82,125)
September	$	(82,125)	307	0.0564%	4	311	(81,814)	(81,970)	3.25%	(222)	(82,036)
October	$	(82,036)	301	0.0564%	2	303	(81,733)	(81,884)	3.25%	(222)	(81,954)
November	$	(81,954)	1,785	0.0564%	2,594	4,379	(77,576)	(79,765)	3.25%	(216)	(77,792)
December	$	(77,792)	3,071	0.0564%	5,681	8,752	(69,039)	(73,415)	3.25%	(199)	(69,238)
January 2011	$	(69,238)	3,651	0.0564%	7,962	11,613	(57,625)	(63,432)	3.25%	(172)	(57,797)
February	$	(57,797)	2,959	0.0564%	6,539	9,498	(48,298)	(53,048)	3.25%	(144)	(48,442)
March	$	(48,442)	2,824	0.0564%	6,580	9,404	(39,039)	(43,740)	3.25%	(118)	(39,157)
April	$	(39,157)	1,343	0.0564%	2,687	4,030	(35,127)	(37,142)	3.25%	(101)	(35,228)

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Sch 4, page 2 of 2, and multiplying by (6.33/365)*Interest Rate.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2011

PEAK PERIOD - Acct 182.16

	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
May 2010	(2,646)	1,918	0.45%	1,405	3,323	677	(985)	3.25%	(3)	674
June	674	3,860	0.45%	34	3,894	4,568	2,621	3.25%	7	4,575
July	4,575	1,387	0.45%	(6)	1,381	5,956	5,266	3.25%	14	5,970
August	5,970	2,954	0.45%	6	2,959	8,930	7,450	3.25%	20	8,950
September	8,950	2,455	0.45%	10	2,465	11,415	10,182	3.25%	28	11,442
October	11,442	2,402	0.45%	6	2,408	13,850	12,646	3.25%	34	13,885
November	13,885	14,247	0.45%	(11,119)	3,128	17,013	15,449	3.25%	42	17,054
December	17,054	24,519	0.45%	(24,293)	226	17,281	17,168	3.25%	46	17,327
January 2011	17,327	29,146	0.45%	(34,004)	(4,858)	12,469	14,898	3.25%	40	12,509
February	12,509	23,621	0.45%	(27,957)	(4,335)	8,174	10,342	3.25%	28	8,202
March	8,202	22,542	0.45%	(28,113)	(5,571)	2,631	5,417	3.25%	15	2,646
April	2,646	10,725	0.45%	(11,442)	(717)	1,929	2,288	3.25%	6	1,935

(1) Bad Debt Allowance calculated by multiplying % Allowed Bad Debt by monthly Total Gas Cost on Sch 4, page 2 of 2, and Working Capital Allowance on Attachment A

Attachment C

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Costs
June 2010 through October 2011

		Beginning Balance	Firm Sales and Transportation (therms)	ERC Recovery/Passback Rate	Current ERC Recoveries/ Passbacks	Ending Balance
June 2010	(act)	$ (13,226)	2,197,606	$ 0.0057	$ 12,529	$ (25,755)
July 2010	(act)	$ (25,755)	1,920,384	$ 0.0057	$ 10,949	$ (36,704)
August 2010	(act)	$ (36,704)	1,919,331	$ 0.0057	$ 10,940	$ (47,645)
September 2010	(act)	$ (47,645)	2,136,181	$ 0.0057	$ 12,159	$ (59,804)
October 2010	(act)	$ (59,804)	2,720,392	$ 0.0057	$ 15,506	$ (75,310)
November 2010 (1) (2)	(act)	$ 291,878	4,391,419	$ 0.0055	$ 24,311	$ 267,567
December 2010	(act)	$ 267,567	7,012,273	$ 0.0054	$ 37,866	$ 229,701
January 2011	(act)	$ 229,701	9,834,669	$ 0.0054	$ 53,107	$ 176,610
February 2011	(act)	$ 176,610	10,176,757	$ 0.0054	$ 54,954	$ 121,656
March 2011	(act)	$ 121,656	8,423,426	$ 0.0054	$ 45,487	$ 76,169
April 2011	(act)	$ 76,169	6,293,586	$ 0.0054	$ 33,985	$ 42,184
May 2011	(act)	$ 42,184	3,702,589	$ 0.0054	$ 19,994	$ 22,190
June 2011	(act)	$ 22,190	2,685,591	$ 0.0054	$ 14,502	$ 7,686
July 2011	(est)	$ 7,686	1,920,384	$ 0.0054	$ 10,370	$ (2,684)
August 2011	(est)	$ (2,684)	1,919,331	$ 0.0054	$ 10,364	$ (13,049)
September 2011	(est)	$ (13,049)	2,136,181	$ 0.0054	$ 11,535	$ (24,584)
October 2011	(est)	$ (24,584)	2,720,392	$ 0.0054	$ 14,690	$ (39,274)

(1) November Beginning Balance includes $367,188 amortization from all prior years at 1/7 of annual costs. (See Section 4.7 of Tariff.)

(2) November Current ERC Recoveries/Passbacks reflect an ERC Rate based on actual Firm Sales and Transportation (therms) at $0.0057 and actual Firm Sales and Transportation (therms) at $0.0054.

Attachment D

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
RLIAP Reconciliation

		Beginning Balance	Program Costs	RLIAP Recoveries	Ending Balance	Average Monthly Balance	Interest Rate	Interest	Ending Balance w/Interest
		A	B	C	D = A + B - C	E = (A +D) / 2	F	G = E * (F / 12)	H = D + G
May 2010	Actual	$ (22,232)	$ 12,692	$ 17,566	$ (27,106)	$ (24,669)	3.25%	$ (67)	$ (27,173)
June 2010	Actual	$ (27,173)	$ 9,157	$ 12,093	$ (30,109)	$ (28,641)	3.25%	$ (78)	$ (30,187)
July 2010	Actual	$ (30,187)	$ 10,108	$ 10,568	$ (30,647)	$ (30,417)	3.25%	$ (82)	$ (30,729)
August 2010	Actual	$ (30,729)	$ 10,200	$ 10,568	$ (31,097)	$ (30,913)	3.25%	$ (84)	$ (31,181)
September 2010	Actual	$ (31,181)	$ 10,113	$ 11,753	$ (32,821)	$ (32,001)	3.25%	$ (87)	$ (32,908)
October 2010	Actual	$ (32,908)	$ 11,515	$ 14,962	$ (36,355)	$ (34,632)	3.25%	$ (94)	$ (36,449)
November 2010	Actual	$ (36,449)	$ 17,234	$ 21,263	$ (40,478)	$ (38,463)	3.25%	$ (104)	$ (40,582)
December 2010	Actual	$ (40,582)	$ 24,840	$ 30,154	$ (45,896)	$ (43,239)	3.25%	$ (117)	$ (46,009)
January 2011	Actual	$ (46,009)	$ 35,235	$ 42,278	$ (53,052)	$ (49,530)	3.25%	$ (134)	$ (53,186)
February 2011	Actual	$ (53,186)	$ 41,627	$ 43,764	$ (55,323)	$ (54,254)	3.25%	$ (147)	$ (55,470)
March 2011	Actual	$ (55,470)	$ 40,571	$ 36,210	$ (51,109)	$ (53,289)	3.25%	$ (144)	$ (51,253)
April 2011	Actual	$ (51,253)	$ 41,194	$ 27,054	$ (37,112)	$ (44,182)	3.25%	$ (120)	$ (37,232)
May 2011	Actual	$ (37,232)	$ 23,941	$ 15,922	$ (29,212)	$ (33,222)	3.25%	$ (90)	$ (29,302)
June 2011	Actual	$ (29,302)	$ 14,720	$ 11,548	$ (26,131)	$ (27,717)	3.25%	$ (75)	$ (26,206)
July 2011	Est.	$ (26,206)	$ 10,108	$ 10,568	$ (26,666)	$ (26,436)	3.25%	$ (72)	$ (26,738)
August 2011	Est.	$ (26,738)	$ 10,200	$ 10,567	$ (27,105)	$ (26,922)	3.25%	$ (73)	$ (27,178)
September 2011	Est.	$ (27,178)	$ 10,113	$ 11,753	$ (28,819)	$ (27,999)	3.25%	$ (76)	$ (28,895)
October 2011	Est.	$ (28,895)	$ 11,515	$ 14,962	$ (32,342)	$ (30,618)	3.25%	$ (83)	$ (32,425)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2010 - 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL
Forecast Calendar Month Sales	304,710	472,252	638,023	542,998	525,753	319,160	2,802,896
Actual Sales	229,220	404,014	634,109	677,776	532,653	395,540	2,873,312
Difference	(75,490)	(68,238)	(3,914)	134,778	6,900	76,380	70,416
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	227,914	395,404	632,020	644,907	537,921	386,609	2,824,775
Actual Sales	229,220	404,014	634,109	677,776	532,653	395,540	2,873,312
Weather Variance	(1,306)	(8,610)	(2,089)	(32,869)	5,268	(8,931)	(48,537)
Total Variance Excluding Weather	(76,796)	(76,848)	(6,003)	101,909	12,168	67,449	21,879
(excl weather effect)							
Variance-difference due to meter count							(11,493)
-difference in load pattern							81,911
SALES							70,417

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2010 - 2011

	NORMAL MMBtu			METERS		
	2010-11 Forecast	2010-11 Actual	Difference	2010-11 Forecast	2010-11 Actual	Difference
Res Heat	1,281,543	1,343,369	61,826	123,762	123,390	(372)
Res General	21,981	24,975	2,994	9,600	9,655	55
Total Res	1,303,524	1,368,344	64,820	133,362	133,045	(317)
G-40	625,444	676,391	50,948	27,128	26,987	(141)
G-50	93,945	101,417	7,473	5,761	5,731	(30)
G-41	564,013	527,995	(36,019)	3,386	3,368	(18)
G-51	140,222	138,471	(1,751)	1,406	1,399	(7)
G-42	69,689	55,613	(14,077)	181	180	(1)
G-52	6,058	5,081	(977)	167	166	(1)
Total C & I	1,499,371	1,504,968	5,598	38,028	37,831	(197) .
Total Company	2,802,895	2,873,312	70,417	171,390	170,876	(514)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2010-11 Forecast	2010-11 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.35	10.89	0.53	(3,852)	65,678	61,826	4.82%
Res General	2.29	2.59	0.30	126	2,868	2,994	13.62%
Total Res	12.64	13.47	0.83	(3,726)	68,546	64,820	4.97%
G-40	23.06	25.06	2.01	(3,240)	54,188	50,948	8.15%
G-50	16.31	17.70	1.39	(487)	7,959	7,473	7.95%
G-41	166.59	156.77	(9.83)	(2,922)	(33,097)	(36,019)	-6.39%
G-51	99.71	98.98	(0.73)	(726)	(1,025)	(1,751)	-1.25%
G-42	385.16	308.96	(76.20)	(361)	(13,716)	(14,077)	-20.20%
G-52	36.30	30.61	(5.69)	(31)	(945)	(977)	-16.12%
Total C & I	39.43	39.78	0.35	(7,767)	13,365	5,598	0.37%
Total Company	16.35	16.82	0.46	(11,493)	81,911	70,417	2.51%

Schedule 16

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
Residential Low Income Assistance Program (RLIAP)

		Customer Charge	First Block	Last Block	Total
1	**Peak Period**				
2	R-5 Base Rates	$9.50	$0.4102	$0.2990	
3	R-10 Rate at 40% of R5	$3.80	$0.1641	$0.1196	
4	Program Subsidy	$5.70	$0.2461	$0.1794	
5	Average Annual Therms		289	586	875
6					
7	Peak Period RLIAP Subsidy	$34.20	$71.06	$105.17	$210.43
8					
9	**Off Peak Period**				
10	R-5 Base Rates	$9.50	$0.4102	$0.2990	
11	R10 Rate at 40% of R5	$3.80	$0.1641	$0.1196	
12	Program Subsidy	$5.70	$0.2461	$0.1794	
13	Average Annual Therms		254	64	318
14					
15	Off Peak Period RLIAP Subsidy	$34.20	$62.61	$11.41	$108.22
16					
17	Estimated Annual Subsidy				$318.65
18					
19	Number of Estimated 2011/12 Participants				1,138
20					
21	Annual Subsidy times Number of Participants (Ln 17 *Ln 19)				$362,626
22	Prior Year Ending Balance - RLIAP Page 2				($20,874)
23	Estimated Annual Administrative Costs				$0
24	Total Program Costs				$341,752
25					
26	Estimated weather normalized firm therms billed for				
27	the twelve months ended 10/31/12 sales and transportation				61,510,387
28					
29	**Total Residential Low Income Program Change**				$0.0056

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
NOVEMBER 2010 THROUGH OCTOBER 2011
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM (RLIAP) RECONCILIATION

												(Estimate)	(Estimate)	(Estimate)
1	**FOR THE MONTH OF:**	**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	**DAYS IN MONTH**	30	31	31	28	31	30	31	30	31	31	30	31	365
3	Beginning Balance	($36,451)	($40,583)	($46,016)	($53,196)	($55,468)	($51,254)	($37,232)	($29,303)	($26,206)	($18,690)	($16,781)	($17,962)	($429,142)
4														
5	Add: Actual Costs	$17,234	$24,840	$35,235	$41,627	$40,571	$41,194	$23,941	$14,720	$16,632	$10,600	$8,195	$9,513	$284,303
6														
7	Less: Collected Revenue	$21,263	$30,154	$42,278	$43,764	$36,210	$27,054	$15,922	$11,548	$9,053	$8,642	$9,330	$12,371	$267,591
8														
9	Add: Administrative and Start Up Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10														
11	Ending Balance Pre-Interest	($40,480)	($45,897)	($53,059)	($55,333)	($51,107)	($37,113)	($29,212)	($26,132)	($18,628)	($16,732)	($17,916)	($20,820)	($412,429)
12														
13	Month's Average Balance	($38,466)	($43,240)	($49,538)	($54,264)	($53,287)	($44,184)	($33,222)	($27,718)	($22,417)	($17,711)	($17,349)	($19,391)	($420,785)
14														
15	Interest 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%	$0
16														
17	Interest Applied	($102.75)	($119.35)	($136.74)	($135.29)	($147.09)	($118.02)	($91.70)	($74.04)	($61.88)	($48.89)	($46.34)	($53.52)	($1,136)
18														
19	Ending Balance	($40,583)	($46,016)	($53,196)	($55,468)	($51,254)	($37,232)	($29,303)	($26,206)	($18,690)	($16,781)	($17,962)	($20,874)	($413,565)

Northern Utilities, Inc. -- New Hampshire Division

Energy Efficiency Budget

	Residential	Low-Income	Gen Service	Total
September-11	$26,186	$5,244	$55,639	$87,070
October-11	$26,186	$5,244	$27,820	$59,250
November-11	$26,186	$5,244	$37,093	$68,523
December-11	$120,352	$25,172	$37,093	$182,616
January-12	$24,231	$6,500	$25,834	$56,565
February-12	$29,077	$7,800	$34,446	$71,323
March-12	$33,923	$9,100	$25,834	$68,857
April-12	$33,923	$9,100	$43,057	$86,080
May-12	$24,231	$6,500	$25,834	$56,565
June-12	$82,385	$22,100	$60,280	$164,765
July-12	$19,385	$5,200	$17,223	$41,808
August-12	$48,462	$13,000	$51,669	$113,130
September-12	$24,231	$6,500	$51,669	$82,399
October-12	$24,231	$6,500	$25,834	$56,565
Total	$562,075	$135,443	$555,852	$1,253,370

Budget with Low-Income Costs Allocated to Residential and General Service Classes

	Residential	Low-Income	Gen Service	Total
September-11	$27,196	0	$59,874	$87,070
October-11	$27,172	0	$32,078	$59,250
November-11	$27,550	0	$40,974	$68,523
December-11	$127,177	0	$55,440	$182,616
January-12	$26,283	0	$30,282	$56,565
February-12	$31,722	0	$39,600	$71,323
March-12	$36,907	0	$31,950	$68,857
April-12	$36,878	0	$49,203	$86,080
May-12	$26,361	0	$30,204	$56,565
June-12	$88,286	0	$76,479	$164,765
July-12	$20,555	0	$21,252	$41,808
August-12	$51,233	0	$61,897	$113,130
September-12	$25,492	0	$56,908	$82,399
October-12	$25,461	0	$31,105	$56,565
Total	$597,682	$0	$655,687	$1,253,370

DSM Charge Factor Calculation

DSM Charge Factors for Residential Customers

DSM Reconciliation Adjustment	($38,385)	Schedule 16 DSM B Nov '11 - Oct '12 Totals- November 2011 Beginning Balance
DSM Costs	$490,616	Schedule 16 DSM B Nov '11 - Oct '12 Totals- Column 2
DSM Share Holder Incentive	$38,256	Schedule 16 DSM B Nov '11 - Oct '12 Totals- Column 3
DSM Low-Income Costs	$33,288	Schedule 16 DSM B Nov '11 - Oct '12 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$2,343	Schedule 16 DSM B Nov '11 - Oct '12 Totals- Column 5
Total	$526,119	
Forecasted Annual Throughput Volumes for Residential Customers	16,714,720	Schedule 16 DSM B Nov '11 - Oct '12 Totals- Column 6
Conservation Charge Factor for Residential Customers	**$0.0315**	

DSM Charge Factors for Commercial and Industrial Customers (C&I)

DSM Reconciliation Adjustment	($189,323)	Schedule 16 DSM C Nov '11 - Oct '12 Totals- November 2011 Beginning Balance
DSM Costs	$435,866	Schedule 16 DSM C Nov '11 - Oct '12 Totals- Column 2
DSM Share Holder Incentive	$34,452	Schedule 16 DSM C Nov '11 - Oct '12 Totals- Column 3
DSM Low-Income Costs	$89,428	Schedule 16 DSM C Nov '11 - Oct '12 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$6,292	Schedule 16 DSM C Nov '11 - Oct '12 Totals- Column 5
Total	$376,714	
Forecasted Annual Throughput Volumes for C&I Customers	40,154,278	Schedule 16 DSM C Nov '11 - Oct '12 Totals- Column 6
Conservation Charge Factor for C&I Customers	**$0.0094**	

Northern Utilities, Inc.

New Hampshire Division

Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge

To Be Effective November 1, 2011 through October 31, 2012

Residential Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Costs	DSM SHI	Allocated Low Income Costs	Allocated Low Income SHI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-10	Actual	$163,601	$0.0185	$5,809	$13,894	$1,724	$5,071	$267	$178,749	$171,175	3.25%	$472	$179,221	313,978	31
September-10	Actual	$179,221	$0.0185	$6,541	$30,378	$1,724	$2,713	$143	$207,638	$193,430	3.25%	$517	$208,155	353,426	30
October-10	Actual	$208,155	$0.0185	$8,380	($8,531)	$1,724	$560	$29	$193,557	$200,856	3.25%	$554	$194,112	452,865	31
November-10	Actual	$194,112	$0.0359	$24,885	$58,977	$1,724	$888	$47	$230,862	$212,487	3.25%	$568	$231,429	1,072,476	30
December-10	Actual	$231,429	$0.0359	$70,287	$30,186	$1,724	$581	$31	$193,664	$212,547	3.25%	$587	$194,251	1,957,958	31
January-11	Actual	$194,251	$0.0359	$104,751	$22,454	$2,973	$1,569	$83	$116,579	$155,415	3.25%	$429	$117,008	2,914,686	31
February-11	Actual	$117,008	$0.0359	$117,432	$17,659	$2,973	$1,245	$66	$21,519	$69,263	3.25%	$173	$21,691	3,271,023	28
March-11	Actual	$21,691	$0.0359	$91,423	$16,137	$2,973	$1,291	$68	($49,263)	($13,786)	3.25%	($38)	($49,301)	2,546,460	31
April-11	Actual	($49,301)	$0.0359	$68,916	$34,661	$2,973	$2,952	$155	($77,475)	($63,388)	3.25%	($169)	($77,644)	1,920,837	30
May-11	Actual	($77,644)	$0.0359	$35,549	$13,813	$2,973	$4,045	$213	($92,148)	($84,896)	3.25%	($234)	($92,383)	990,209	31
June-11	Actual	($92,383)	$0.0359	$21,606	$20,884	$2,973	$507	$27	($89,599)	($90,991)	3.25%	($243)	($89,842)	602,071	30
July-11	Actual	($89,842)	$0.0359	$14,354	$24,549	$2,973	$591	$31	($76,051)	($82,946)	3.25%	($229)	($76,280)	399,823	31
August-11	Actual	($76,280)	$0.0359	$11,511	$19,087	$2,973	$323	$138	($65,270)	($70,775)	3.25%	($195)	($65,466)	320,645	31
September-11	Forecast	($65,464)	$0.0359	$15,274	$26,186	$2,973	$1,010	$126	($50,442)	($57,953)	3.25%	($155)	($50,597)	425,454	30
October-11	Forecast	($50,597)	$0.0359	$17,933	$26,186	$2,973	$986	$123	($38,262)	($44,430)	3.25%	($123)	($38,385)	499,521	31
November-11	Forecast	**($38,385)**	$0.0315	$35,707	$26,186	$2,973	$1,363	$170	($43,399)	($40,892)	3.25%	($109)	($43,509)	1,134,391	30
December-11	Forecast	($43,509)	$0.0315	$60,252	$120,352	$2,973	$6,825	$177	$26,566	($8,471)	3.25%	($23)	$26,543	1,914,197	31
January-12	Forecast	$26,543	$0.0315	$88,907	$24,231	$3,231	$2,052	$231	($32,619)	($3,038)	3.25%	($8)	($32,627)	2,824,571	31
February-12	Forecast	($32,627)	$0.0315	$94,420	$29,077	$3,231	$2,645	$249	($91,845)	($62,236)	3.25%	($155)	($92,000)	2,999,701	28
March-12	Forecast	($92,000)	$0.0315	$78,830	$33,923	$3,231	$2,984	$240	($130,452)	($111,226)	3.25%	($307)	($130,759)	2,504,429	31
April-12	Forecast	($130,759)	$0.0315	$57,863	$33,923	$3,231	$2,954	$238	($148,275)	($139,517)	3.25%	($373)	($148,648)	1,838,295	30
May-12	Forecast	($148,648)	$0.0315	$35,101	$24,231	$3,231	$2,130	$240	($153,917)	($151,282)	3.25%	($418)	($154,334)	1,115,146	31
June-12	Forecast	($154,334)	$0.0315	$20,782	$82,385	$3,231	$5,901	$196	($83,403)	($118,869)	3.25%	($318)	($83,721)	660,252	30
July-12	Forecast	($83,721)	$0.0315	$13,322	$19,385	$3,231	$1,170	$165	($73,092)	($78,406)	3.25%	($216)	($73,308)	423,238	31
August-12	Forecast	($73,308)	$0.0315	$11,610	$48,462	$3,231	$2,771	$156	($30,298)	($51,803)	3.25%	($143)	($30,441)	368,861	31
September-12	Forecast	($30,441)	$0.0315	$13,489	$24,231	$3,231	$1,261	$142	($15,065)	($22,753)	3.25%	($61)	($15,126)	428,549	30
October-12	Forecast	($15,126)	$0.0315	$15,835	$24,231	$3,231	$1,230	$139	($2,130)	($8,628)	3.25%	($24)	($2,154)	503,090	31
Nov 11 thru Oct 12 Totals				$526,118	$490,616	$38,256	$33,288	$2,343						16,714,720	

Northern Utilities, Inc.

New Hampshire Division

Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge

To Be Effective November 1, 2011 through October 31, 2012

General Service Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Costs	DSM SHI	Allocated Low Income Costs	Allocated Low Income SHI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-10	Actual	($149,529)	$0.0054	$8,669	$30,130	$2,659	$25,930	$1,365	($98,115)	($123,822)	3.25%	($342)	($98,457)	1,605,354	31
September-10	Actual	($98,457)	$0.0054	$9,617	$35,723	$2,659	$13,685	$720	($55,286)	($76,871)	3.25%	($205)	($55,491)	1,782,755	30
October-10	Actual	($55,491)	$0.0054	$12,245	$50,338	$2,659	$2,803	$148	($11,789)	($33,641)	3.25%	($93)	($11,882)	2,267,527	31
November-10	Actual	($11,882)	$0.0152	$38,691	$19,446	$2,659	$2,749	$145	($25,575)	($18,729)	3.25%	($50)	($25,625)	3,318,943	30
December-10	Actual	($25,625)	$0.0152	$76,818	$101,802	$2,659	$1,500	$79	$3,596	($11,016)	3.25%	($30)	$3,565	5,054,315	31
January-11	Actual	$3,565	$0.0152	$105,184	$17,968	$2,894	$3,726	$196	($76,834)	($36,635)	3.25%	($1,191)	($78,025)	6,919,983	31
February-11	Actual	($78,025)	$0.0152	$104,940	$22,338	$2,894	$2,628	$138	($154,966)	($116,496)	3.25%	($290)	($155,256)	6,905,734	28
March-11	Actual	($155,256)	$0.0152	$89,429	$54,389	$2,894	$2,980	$157	($184,266)	($169,762)	3.25%	$627	($183,639)	5,876,966	31
April-11	Actual	($183,639)	$0.0152	$66,466	$23,217	$2,894	$6,719	$354	($216,921)	($200,281)	3.25%	($535)	($217,456)	4,372,750	30
May-11	Actual	($217,456)	$0.0152	$41,219	$15,915	$2,894	$11,081	$583	($228,200)	($222,829)	3.25%	($615)	($228,815)	2,712,380	31
June-11	Actual	($228,815)	$0.0152	$31,670	$20,821	$2,894	$1,753	$92	($234,925)	($231,872)	3.25%	($619)	($235,544)	2,083,520	30
July-11	Actual	($235,544)	$0.0152	$25,935	$13,947	$2,894	$2,522	$133	($241,983)	($238,767)	3.25%	($659)	($242,643)	1,706,281	31
August-11	Actual	($242,643)	$0.0152	$25,700	$36,527	$2,894	$1,916	$515	($226,491)	($234,567)	3.25%	($647)	($227,138)	1,690,750	31
September-11	Forecast	($227,138)	$0.0152	$27,108	$55,639	$2,894	$4,234	$527	($190,952)	($209,045)	3.25%	($558)	($191,510)	1,783,427	30
October-11	Forecast	($191,510)	$0.0152	$32,791	$27,820	$2,894	$4,258	$530	($188,798)	($190,154)	3.25%	($525)	($189,323)	2,157,275	31
November-11	Forecast	**($189,323)**	$0.0094	$30,298	$37,093	$2,871	$3,881	$483	($175,293)	($182,308)	3.25%	($487)	($175,780)	3,229,478	30
December-11	Forecast	($175,780)	$0.0094	$48,276	$37,093	$2,871	$18,347	$476	($165,270)	($170,525)	3.25%	($471)	($165,741)	5,145,723	31
January-12	Forecast	($165,741)	$0.0094	$57,435	$25,834	$2,871	$4,448	$502	($189,521)	($177,631)	3.25%	($490)	($190,011)	6,122,047	31
February-12	Forecast	($190,011)	$0.0094	$54,836	$34,446	$2,871	$5,155	$484	($201,891)	($195,951)	3.25%	($489)	($202,380)	5,845,019	28
March-12	Forecast	($202,380)	$0.0094	$48,157	$25,834	$2,871	$6,116	$493	($215,224)	($208,802)	3.25%	($576)	($215,800)	5,133,103	31
April-12	Forecast	($215,800)	$0.0094	$35,873	$43,057	$2,871	$6,146	$495	($199,104)	($207,452)	3.25%	($554)	($199,658)	3,823,761	30
May-12	Forecast	($199,658)	$0.0094	$21,460	$25,834	$2,871	$4,370	$493	($187,550)	($193,604)	3.25%	($534)	($188,084)	2,287,477	31
June-12	Forecast	($188,084)	$0.0094	$17,003	$60,280	$2,871	$16,199	$537	($125,200)	($156,642)	3.25%	($418)	($125,618)	1,812,405	30
July-12	Forecast	($125,618)	$0.0094	$13,670	$17,223	$2,871	$4,030	$568	($114,597)	($120,107)	3.25%	($332)	($114,929)	1,457,087	31
August-12	Forecast	($114,929)	$0.0094	$12,772	$51,669	$2,871	$10,229	$577	($62,356)	($88,642)	3.25%	($245)	($62,601)	1,361,363	31
September-12	Forecast	($62,601)	$0.0094	$16,704	$51,669	$2,871	$5,239	$591	($18,935)	($40,768)	3.25%	($109)	($19,044)	1,780,532	30
October-12	Forecast	($19,044)	$0.0094	$20,230	$25,834	$2,871	$5,270	$594	($4,705)	($11,875)	3.25%	($33)	($4,738)	2,156,283	31
Nov 11 thru Oct 12 Totals				$376,714	$435,866	$34,452	$89,428	$6,292						40,154,278	

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE

November 1, 2011 through October 31, 2012

Total ERC Costs for the Period	$342,842
Less Current (Over) Collection (Estimated)	($14,554)
Total ERC Cost to be Recovered	$328,288
Forcasted Firm Sales & Firm Transportation Volumes	61,510,387
ERC Recovery Rate	**$0.0053**

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Cost 12 Month Reconciliation

Month	Actual or Forecast	Beginning Balance (Over)/Under	Monthly Amortization of ERC costs	New ERC Costs To be recovered	Ending Balance
August	Actual	($36,705)	$10,940		($47,645)
September	Actual	($47,645)	$12,160		($59,805)
October	Actual	($59,805)	$15,503		($75,308)
November-'10	Actual	($75,308)	$24,311	$367,188	$267,569
December	Actual	$267,569	$37,869		$229,701
January- '11	Actual	$229,701	$53,091		$176,610
February	Actual	$176,610	$54,961		$121,649
March	Actual	$121,649	$45,486		$76,163
April	Actual	$76,163	$33,978		$42,186
May	Actual	$42,186	$19,994		$22,192
June	Actual	$22,192	$14,506		$7,686
July	Actual	$7,686	$11,378		($3,693)
August	Actual	($3,693)	$10,860		($14,554)

Schedule 17

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDIATION ADJUSTMENT CLAUSE COMPLIANE FILING
2010-2011 ENVIORMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES

Line	Description	Total	11/05 - 10/06	11/06 - 10/07	11/07 - 10/08	11/08 - 10/09	11/09 - 10/10	11/10 - 10/11	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14 10/15	11/15-10/16	11/16-10/17	11/17-10/18
	ENVIRONMENTAL RESPONSE COST (ERC)														
1	July 04 - June 05 Expenses Amortization (1/7)	$ 909,099	$ 129,871	$ 129,871	$ 129,871	$ 129,871	$ 129,871	$ 129,871	$ 129,871						
2	July 05 - June 06 Expenses Amortization (1/7)	$ 632,461		$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352					
3	July 06 - June 07 Expenses Amortization (1/7)	$ 186,804			$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686				
4	July 07 - June 08 Expenses Amortization (1/7)	$ 232,960				$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280			
5	July 08 - June 09 Expenses Amortization (1/7)	$ 127,728					$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247		
6	July 09 - June 10 Expenses Amortization (1/7)	$ 189,634						$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	
7	July 10 - June 11 Expenses Amortization (1/7)	$ 121,209							$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316
8	Subtotal (Line 1 through Line 7)	$ 2,399,895	$ 129,871	$ 220,223	$ 246,909	$ 280,189	$ 298,436	$ 325,527	$ 342,842	$ 212,971	$ 122,619	$ 95,933	$ 62,653	$ 44,406	$ 17,316
9	Add: Excess amortization from prior years (from schedule 5, Line 10)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Less: Excess amortization to be deferred (from schedule 5, Line 9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total Enviromental Response cost to be recovered (ERC)	$ 2,399,895	$ 129,871	$ 220,223	$ 246,910	$ 280,189	$ 298,436	$ 325,527	$ 342,842	$ 212,971	$ 122,619	$ 95,933	$ 62,653	$ 44,406	$ 17,316
	UNAMORTIZED ENVIRONMENTAL RESPONSE COST														
12	July 2004 - June 2005 Unamortized beginning balance		$ 909,099	$ 779,228	$ 649,356	$ 519,485	$ 389,614	$ 259,743	$ 129,871	$ 0					
13	July 2005 - June 2006 Unamortized beginning balance			$ 632,461	$ 542,109	$ 451,758	$ 361,406	$ 271,055	$ 180,703	$ 90,352	$ -				
14	July 2006 - June 2007 Unamortized beginning balance				$ 186,804	$ 160,118	$ 133,431	$ 106,745	$ 80,059	$ 53,373	$ 26,686	$ -			
15	July 2007 - June 2008 Unamortized beginning balance					$ 232,960	$ 199,680	$ 166,400	$ 133,120	$ 99,840	$ 66,560	$ 33,280	$ -		
16	July 2008 - June 2009 Unamortized beginning balance						$ 127,728	$ 109,481	$ 91,234	$ 72,987	$ 54,741	$ 36,494	$ 18,247	$ -	
17	July 2009 - June 2010 Unamortized beginning balance							$ 189,634	$ 162,544	$ 135,453	$ 108,362	$ 81,272	$ 54,181	$ 27,091	$ -
18	July 2010 - June 2011 Unamortized beginning balance								$ 121,209	$ 103,893	$ 86,578	$ 69,262	$ 51,947	$ 34,631	$ 17,316
18	Total Unamortized beginning balance		$ 1,318,796	$ 1,747,779	$ 2,690,645	$ 2,455,173	$ 1,327,128	$ 1,144,719	$ 898,740	$ 555,898	$ 342,927	$ 220,308	$ 124,375	$ 61,722	$ 17,316
19	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)														
20	INSURANCE/3RD PARTY RECOVERIES (IR)														
21	UNDER/OVER Recovery from previous year														
22	**Total of Lines 15, 16, 17, 18**		$ 1,318,796	$ 1,747,779	$ 2,690,645	$ 2,455,173	$ 1,327,128	$ 1,144,719	$ 898,740	$ 555,898	$ 342,927	$ 220,308	$ 124,375	$ 61,722	$ 17,316

Schedule 18

Northern Utilities, Inc.- New Hampshire
Calculation of Balancing Charge

November 2011 through October 2012

		MDQ	Max Swing	% MDQ
1	New Hampshire Underground	16,882	3,532	20.92%
2	LNG	0	0	0.00%
3	Propane	0	0	0.00%

		% MDQ	Costs	Balancing Costs	% Allocated	Allocated Costs
4	Maine Underground					
5	Del., Res., and Transp.	20.92%	$14,598,377	$3,054,254	0.20%	$6,116
6	Capacity	20.92%	$1,405,254	$294,005	35.64%	$104,779
7	LNG	0.00%	$95,251	$0	0.00%	$0
8	Propane	0.00%	$119,843	$0	0.00%	$0
9	Total		$16,218,725	$3,348,260		$110,894
10	Annual Sum of Absolute Swings					142,624
11	Balancing Rate Per MMBtu Swing					**$0.78**

Note: LNG and LP MDQ allocated based on Maine's current PR-Allocator percentage. 47.35%

Schedule 19

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2011-2012
Derivation of Class Assignments and Weightings

Basic assumptions:

1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
   a The base use portion of the class design day demand based on base use
   b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

			Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total	Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	348	3,480	331	0.7%	56	275
2	RATE B-Resi Htg	19,246	192,460	18,288	36.2%	1,528	16,760
3	RATE G-40 (R)	8,482	84,820	8,060	15.9%	435	7,625
4	RATE G-50 (Q)	1,074	10,740	1,021	2.0%	340	681
5	RATE G-41 (T)	7,609	76,090	7,230	14.3%	541	6,689
6	RATE G-51 (S)	1,436	14,360	1,365	2.7%	454	911
7	RATE G-42 (V)	1,074	10,740	1,021	2.0%	67	954
8	RATE G-52a (U)	54	540	51	0.1%	19	32
9	Special Contract	0	7,903	751	1.5%	3,070	-
10	RATE T-40	1,186	11,864	1,127	2.2%	39	1,088
11	RATE T-50	142	1,420	135	0.3%	80	55
12	RATE T-41	5,614	56,139	5,334	10.5%	270	5,064
13	RATE T-51	407	4,070	387	0.8%	275	112
14	RATE T-42	3,693	36,927	3,509	6.9%	350	3,159
15	RATE T-52	2,083	20,830	1,979	3.9%	804	1,175
16	Total		532,383	50,588	100.0%	8,328	44,579
17			53,238				-
18	Residential Total		195,940	18,618	**36.8%**	1,584	17,035
19	LLF Total		276,580	26,281	52.0%	1,702	24,579
20	HLF Total		59,863	5,688	11.2%	5,042	646
21	Total		532,383	50,588	100.0%	8,328	42,260

22						
23						
24			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
25	Pipeline		3,230,839	13,931	19.33	
26	Storage		16,005,646	16,823	79.28	
27	Peaking		1,299,096	19,834	5.46	
28	Total		20,535,581	50,588	**33.83**	**81.19**
29						
30						
31						
32			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
33	Pipeline - Baseload		1,931,438	8,328	19.33	
34	Pipeline - Remaining		1,299,401	5,603	19.33	
35	Storage		16,005,646	16,823	79.28	
36	Peaking		1,299,096	19,834	5.46	
37	Total		20,535,581	50,588	33.83	
38						
39						
40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
41	Pipeline - Base	**36.8%**	710,853	3,065	19.33	
42	Pipeline - Remaining	**36.8%**	478,236	2,062	19.33	
43	Storage	**36.8%**	5,890,771	6,192	79.28	
44	Peaking	**36.8%**	478,124	7,300	5.46	
45	Total	**36.8%**	7,557,983	18,618	33.83	

Line						
1	C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
2	Pipeline - Base		1,220,585	5,263	19.33	
3	Pipeline - Remaining		821,165	3,541	19.33	
4	Storage		10,114,875	10,631	79.28	
5	Peaking		820,972	12,534	5.46	
6	Total	**63.2%**	12,977,598	31,969	33.83	
7						
8						
9	LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
10	Pipeline - Base		308,036	1,328	19.33	
11	Pipeline - Remaining		800,131	3,450	19.33	
12	Storage		9,855,782	10,359	79.28	
13	Peaking		799,943	12,213	5.46	
14	Total	**57.3%**	11,763,893	27,350	**35.84**	
15						
16						
17	HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
18	Pipeline - Base		912,549	3,935	19.33	
19	Pipeline - Remaining		21,034	91	19.33	
20	Storage		259,093	272	79.28	
21	Peaking		21,029	321	5.46	
22	Total	**5.9%**	1,213,705	4,619	**21.90**	
23						
24						
25	Unit Cost		Residential	LLF C&I	HLF C&I	
26						
27	Pipeline		$ 19.33	$ 19.33	$ 19.33	
28	Storage		$ 79.28	$ 79.28	$ 79.28	
29	Peaking		$ 5.46	$ 5.46	$ 5.46	
30	Total		$ 33.83	$ 35.84	$ 21.90	
31	Checktotal		$ 33.83	$ 35.84	$ 21.90	
32						
33						
34	Load Makeup		Residential	**LLF C&I**	**HLF C&I**	
35						
36	Pipeline		27.54%	**17.47%**	**87.15%**	
37	Storage		33.26%	**37.88%**	**5.90%**	
38	Peaking		39.21%	**44.65%**	**6.95%**	
39	Total		100.00%	**100.00%**	**100.00%**	
40						
41						
42	Supply Makeup		Residential	LLF C&I	HLF C&I	Total
43						
44	Pipeline		36.80%	34.30%	28.90%	100.00%
45	Storage		36.80%	61.58%	1.62%	100.00%
46	Peaking		36.80%	61.58%	1.62%	100.00%

Storage and Peaking

LLF C&I	**HLF C&I**
NA	**NA**
45.89%	**45.89%**
54.11%	**54.11%**

Schedule 20

RESERVED FOR HEDGING PROGRAM

Schedule 21

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	$ 10,419,440
Storage Demand	$ 33,802,842
Peaking Demand	$ 1,812,610
Subtotal Demand	$ 46,034,892
Litigation Expense - PNGTS Invoices	$ 380,866
Capacity Release (Credit)	$ (313,490)
Asset Management (Credit)	$ (4,087,000)
Total Net Demand Costs	$ 42,015,269

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	952,333	866,002	822,579	743,372	916,712	792,961	539,352	413,419	367,754	351,109	374,449	634,030	7,774,072
Rank	1	3	4	6	2	5	8	9	11	12	10	7	
% Max Month	100.00%	90.93%	86.38%	78.06%	96.26%	83.27%	56.63%	43.41%	38.62%	36.87%	39.32%	66.58%	
PR	3.74%	1.52%	0.78%	1.91%	2.66%	1.04%	1.65%	0.45%	0.16%	3.07%	0.07%	1.42%	18.48%
CumPR	18.48%	12.08%	10.56%	8.74%	14.74%	9.78%	5.41%	3.76%	3.23%	3.07%	3.30%	6.83%	100.00%
Product and Pipeline Demand Costs	$ 1,925,993	$ 1,258,858	$ 1,100,494	$ 910,972	$ 1,536,266	$ 1,019,481	$ 563,606	$ 391,378	$ 336,678	$ 320,123	$ 344,003	$ 711,588	$ 10,419,440

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	504,390	574,802	556,260	574,802	574,802	551,060	283,758	3,619,874
Design Year Pipeline Sendout	952,333	866,002	822,579	743,372	916,712	792,961	539,352	413,419	367,754	351,109	374,449	634,030	7,774,072
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	38.9%	51.6%	57.4%	61.0%	62.1%	59.5%	30.9%	31.8%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 396,359	$ 290,769	$ 224,515	$ 205,318	$ 198,731	$ 204,824	$ 220,006	$ 1,740,522

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	-	654,361	1,042,725	956,652	685,269	203,848	-	-	-	-	-	-	3,542,855
Rank	6	4	1	2	3	5	6	6	6	6	6	6	
% Max Month	0.00%	62.75%	100.00%	91.75%	65.72%	19.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	10.80%	8.25%	13.01%	0.99%	3.91%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.97%
CumPR	0.00%	14.71%	36.97%	28.71%	15.70%	3.91%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ -	$ 4,972,821	$ 12,495,935	$ 9,705,622	$ 5,306,804	$ 1,321,660	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,802,842
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 396,359	$ 290,769	$ 224,515	$ 205,318	$ 198,731	$ 204,824	$ 220,006	$ 1,740,522
TOTAL	$ -	$ 4,972,821	$ 12,495,935	$ 9,705,622	$ 5,306,804	$ 1,718,019	$ 290,769	$ 224,515	$ 205,318	$ 198,731	$ 204,824	$ 220,006	$ 35,543,364

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	1,350	16,259	160,863	68,127	8,334	5,517	1,395	1,350	1,395	1,395	1,350	2,123	269,458
Rank	12	3	1	2	4	5	9	11	8	7	10	6	
% Max Month	0.84%	10.11%	100.00%	42.35%	5.18%	3.43%	0.87%	0.84%	0.87%	0.87%	0.84%	1.32%	
PR	0.07%	1.64%	57.65%	16.12%	0.44%	0.42%	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%	76.42%
CumPR	0.07%	2.65%	76.42%	18.77%	1.01%	0.57%	0.07%	0.07%	0.07%	0.07%	0.07%	0.15%	100.00%
Peaking Demand Costs	$ 1,268	$ 48,041	$ 1,385,218	$ 340,269	$ 18,276	$ 10,341	$ 1,324	$ 1,268	$ 1,324	$ 1,324	$ 1,268	$ 2,691	$ 1,812,610

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

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	Litigation Expense - PNGTS	Schedule 1A page 6 LN 2
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-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL
50	Pipeline & Product Demand	$ 1,925,993	$ 1,258,858	$ 1,100,494	$ 910,972	$ 1,536,266	$ 1,019,481	$ 563,606	$ 391,378	$ 336,678	$ 320,123	$ 344,003	$ 711,588	$ 10,419,440
51	Storage Incld Inj Fees	$ -	$ 4,972,821	$ 12,495,935	$ 9,705,622	$ 5,306,804	$ 1,718,019	$ 290,769	$ 224,515	$ 205,318	$ 198,731	$ 204,824	$ 220,006	$ 35,543,364
52	Peaking	$ 1,268	$ 48,041	$ 1,385,218	$ 340,269	$ 18,276	$ 10,341	$ 1,324	$ 1,268	$ 1,324	$ 1,324	$ 1,268	$ 2,691	$ 1,812,610
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (396,359)	$ (290,769)	$ (224,515)	$ (205,318)	$ (198,731)	$ (204,824)	$ (220,006)	$ (1,740,522)
54	Less: Capacity Release	$ (62,698)	$ (62,698)	$ (62,698)	$ (62,698)	$ (62,698)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (313,490)
55	Less: Asset Mgmt	$ (681,167)	$ (681,167)	$ (681,167)	$ (681,167)	$ (681,167)	$ (681,167)		$ -	$ -	$ -	$ -	$ -	$ (4,087,000)
56	Total Demand	$ 1,183,396	$ 5,535,854	$ 14,237,783	$ 10,212,998	$ 6,117,482	$ 1,670,316	$ 564,930	$ 392,645	$ 338,002	$ 321,447	$ 345,271	$ 714,278	$ 41,634,403
57														
58	**Capacity Cost Allocator based on Design Year Firm Sendout**													
59		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL
60	**Therms**													
61	Maine	519,106	831,371	1,055,929	919,519	843,747	535,094	284,050	220,889	200,842	195,522	204,694	353,883	6,164,646
62	New Hampshire	434,577	705,251	970,238	848,632	766,568	467,232	256,697	193,880	168,307	156,982	171,105	282,270	5,421,739
63	Total	953,683	1,536,622	2,026,167	1,768,151	1,610,315	1,002,326	540,747	414,769	369,149	352,504	375,799	636,153	11,586,385
64	**Percentage of Total**	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL
65	Maine	54.43%	54.10%	52.11%	52.00%	52.40%	53.39%	52.53%	53.26%	54.41%	55.47%	54.47%	55.63%	52.65%
66	New Hampshire	45.57%	45.90%	47.89%	48.00%	47.60%	46.61%	47.47%	46.74%	45.59%	44.53%	45.53%	44.37%	47.35%
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	$644,143	$2,995,108	$7,419,965	$5,311,224	$3,205,340	$891,702	$296,753	$209,107	$183,896	$178,295	$188,066	$397,343	$21,920,942
71	New Hampshire	$539,253	$2,540,746	$6,817,818	$4,901,774	$2,912,142	$778,614	$268,177	$183,538	$154,106	$143,151	$157,205	$316,935	$19,713,461
72	Total	$ 1,183,396	$ 5,535,854	$ 14,237,783	$ 10,212,998	$ 6,117,482	$ 1,670,316	$ 564,930	$ 392,645	$ 338,002	$ 321,447	$ 345,271	$ 714,278	$ 41,634,403

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

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	
74	**Maine**														
75	Pipeline & Product Demand	$ 1,048,351	$ 681,090	$ 573,518	$ 473,747	$ 804,948	$ 544,252	$ 296,058	$ 208,432	$ 183,176	$ 177,561	$ 187,375	$ 395,846	$ 5,574,354	53.50%
76	Storage Incld Injection Fees	$ -	$ 2,690,485	$ 6,512,208	$ 5,047,365	$ 2,780,574	$ 917,168	$ 152,739	$ 119,568	$ 111,707	$ 110,229	$ 111,566	$ 122,386	$ 18,675,995	52.54%
77	Peaking	$ 690	$ 25,992	$ 721,901	$ 176,955	$ 9,576	$ 5,521	$ 695	$ 675	$ 720	$ 734	$ 690	$ 1,497	$ 945,647	52.17%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (211,597)	$ (152,739)	$ (119,568)	$ (111,707)	$ (110,229)	$ (111,566)	$ (122,386)	$ (939,791)	
79	Capacity Release (Credit)	$ (34,128)	$ (33,922)	$ (32,675)	$ (32,606)	$ (32,851)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (166,182)	53.01%
80	Asset Management -(Credit)	$ (370,771)	$ (368,537)	$ (354,987)	$ (354,238)	$ (356,907)	$ (363,642)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,169,082)	53.07%
81	**Total Allocated Demand**	$ 644,143	$ 2,995,108	$ 7,419,965	$ 5,311,224	$ 3,205,340	$ 891,702	$ 296,753	$ 209,107	$ 183,896	$ 178,295	$ 188,066	$ 397,343	$ 21,920,942	52.65%
82															
83	**New Hampshire**	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	
84	Pipeline & Product Demand	$ 877,642	$ 577,768	$ 526,976	$ 437,225	$ 731,318	$ 475,229	$ 267,548	$ 182,946	$ 153,503	$ 142,561	$ 156,628	$ 315,741	$ 4,845,086	46.50%
85	Storage Incld Injection Fees	$ -	$ 2,282,335	$ 5,983,727	$ 4,658,257	$ 2,526,230	$ 800,851	$ 138,031	$ 104,948	$ 93,611	$ 88,502	$ 93,258	$ 97,620	$ 16,867,369	47.46%
86	Peaking	$ 578	$ 22,049	$ 663,317	$ 163,314	$ 8,700	$ 4,820	$ 629	$ 593	$ 604	$ 590	$ 577	$ 1,194	$ 866,963	47.83%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (184,762)	$ (138,031)	$ (104,948)	$ (93,611)	$ (88,502)	$ (93,258)	$ (97,620)	$ (800,730)	
88	Capacity Release	$ (28,570)	$ (28,776)	$ (30,023)	$ (30,092)	$ (29,846)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (147,308)	46.99%
89	Asset Management	$ (310,396)	$ (312,630)	$ (326,179)	$ (326,929)	$ (324,260)	$ (317,524)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,917,918)	46.93%
90	PNGTS Expense	$ 63,478	$ 63,478	$ 63,478	$ 63,478	$ 63,478	$ 63,478							$ 380,866	
91	**Total Allocated Demand**	$ 602,731	$ 2,604,224	$ 6,881,296	$ 4,965,252	$ 2,975,620	$ 842,092	$ 268,177	$ 183,538	$ 154,106	$ 143,151	$ 157,205	$ 316,935	$ 19,713,461	47.35%

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

LN		
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
	PNGTS Expense	LN 7
90	**Total Allocated Demand**	Sum (LN 84 : LN 89)

Schedule 22

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	TOTAL	WINTER
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	617,729	568,332	359,160	276,160	525,649	609,348	9,782,123	2,956,378
3	Total Storage	84,573	462,347	823,299	755,281	397,577	0	2,523,077	2,523,077
4	Total Peaking	1,350	1,395	3,453	1,305	1,395	3,120	20,298	12,018
5	Subtotal	703,652	1,032,074	1,185,912	1,032,746	924,621	612,468	12,325,498	5,491,472
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	703,652	1,032,074	1,185,912	1,032,746	924,621	612,468	12,325,498	5,491,472
9	Total Firm Pipeline Sendout	617,729	568,332	359,160	276,160	525,649	609,348	9,782,123	2,956,378
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	$ 21,928,980	$ 15,103,235
12	NYMEX Price Used for Forecast	$4.043	$4.259	$4.383	$4.390	$4.359	$4.344		
13	NYMEX Price Used for Update	$4.043	$4.259	$4.383	$4.390	$4.359	$4.344		
14	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
15	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -		
16	Total Updated Pipeline Costs	$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	$ 21,928,980	$ 15,103,235
17									
18	Total Pipeline	$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	$ 21,928,980	$ 15,103,235
19	Total Storage	$ 383,444	$ 2,096,823	$ 3,735,885	$ 3,427,295	$ 1,805,693	$ -	$ 11,449,140	$ 11,449,140
20	Total Peaking	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 133,875	$ 81,502
21	Subtotal	$ 3,387,026	$ 5,011,087	$ 5,771,243	$ 5,037,140	$ 4,581,341	$ 2,846,040	$ 33,511,995	$ 26,633,877
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	9	16	21	22	17	11	108	96
26	Average Purchase Price	$ 5.021	$ 5.379	$ 5.436	$ 5.418	$ 5.414	$ 4.971		
27	NYMEX Price Used for Forecast	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344		
28	NYMEX Price Used for Update	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344		
29	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
30	Futures Hedging (Gain)/Loss - Allocate	$ 87,980	$ 179,160	$ 221,170	$ 226,200	$ 179,370	$ 69,010	$ 994,550	$ 962,890
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	-	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344		
35	NYMEX Price Used for Update	$ 4.043	$ 4.259	$ 4.383	$ 4.390	$ 4.359	$ 4.344		
36	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	$ 21,928,980	$ 15,103,235
41	Average Supply Cost ($/MMBtu)	$ 4.848	$ 5.112	$ 5.600	$ 5.796	$ 5.262	$ 4.637		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	$ 21,928,980	$ 15,103,235
46	Total Storage	$ 383,444	$ 2,096,823	$ 3,735,885	$ 3,427,295	$ 1,805,693	$ -	$ 11,449,140	$ 11,449,140
47	Total Peaking	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 133,875	$ 81,502
48	Firm Sales Variable Costs Excld Hedge	$ 3,387,026	$ 5,011,087	$ 5,771,243	$ 5,037,140	$ 4,581,341	$ 2,846,040	$ 33,511,995	$ 26,633,877
49	Plus Hedging (Gain)/Loss	$ 87,980	$ 179,160	$ 221,170	$ 226,200	$ 179,370	$ 69,010	$ 994,550	$ 962,890
50	Total Firm Sales Variable Costs	$ 3,475,006	$ 5,190,247	$ 5,992,413	$ 5,263,340	$ 4,760,711	$ 2,915,050	$ 34,506,545	$ 27,596,767

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		New Hampshire Reference
1	Supply Volumes - MMBtu	
2	Total Pipeline	Schedule 6A, page 2
3	Total Storage	Schedule 6A, page 2
4	Total Peaking	Schedule 6A, page 2
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Company Analysis
7	Less Interruptible - New Hampshire	Company Analysis
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™	Schedule 6A, page 1
12	NYMEX Price Used for Forecast	Attachment to Schedule 6B, page 1
13	NYMEX Price Used for Update	Attachment to Schedule 6B, page 1
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	Schedule 6A, page 1
20	Total Peaking	Schedule 6A, 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	Schedule 7
26	Average Purchase Price	Schedule 7
27	NYMEX Price Used for Forecast	Line 14
28	NYMEX Price Used for Update	Schedule 7
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	Schedule 7
33	Average Purchase Price	Schedule 7
34	NYMEX Price Used for Forecast	Line 14
35	NYMEX Price Used for Update	Schedule 7
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

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	TOTAL	WINTER
Maine	334,085	486,717	562,697	486,132	439,785	293,457	3,288,563	2,602,873
New Hampshire	369,569	545,359	623,217	546,616	484,838	319,013	3,642,681	2,888,612
Total	703,654	1,032,076	1,185,914	1,032,748	924,623	612,470	6,931,244	5,491,485
Percentage of Total								
Maine	47.48%	47.16%	47.45%	47.07%	47.56%	47.91%	47.45%	47.40%
New Hampshire	52.52%	52.84%	52.55%	52.93%	52.44%	52.09%	52.55%	52.60%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Commodity Allocation by Jurisdiction								
Maine								
Firm Sales Pipeline Commodity Excld Hedge	$ 1,421,918	$ 1,370,041	$ 954,367	$ 753,400	$ 1,315,549	$ 1,353,773	$ 10,419,482	$ 7,169,047
Hedging (Gains) Losses	$ 41,772	$ 84,490	$ 104,942	$ 106,476	$ 85,315	$ 33,065	$ 471,167	$ 456,060
Storage	$ 182,054	$ 988,841	$ 1,772,617	$ 1,613,286	$ 858,854	$ -	$ 5,415,653	$ 5,415,653
Peaking	$ 4,141	$ 4,298	$ 11,378	$ 4,381	$ 4,652	$ 9,870	$ 63,669	$ 38,720
Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Maine Commodity Costs	$ 1,649,884	$ 2,447,670	$ 2,843,303	$ 2,477,543	$ 2,264,371	$ 1,396,708	$ 16,369,971	$ 13,079,479
Maine Inventory Finance Costs	$ 776	$ 1,259	$ 1,504	$ 1,277	$ 1,107	$ 644	$ 6,567	$ 6,567
Total Maine Variable Costs	$ 1,650,659	$ 2,448,929	$ 2,844,807	$ 2,478,820	$ 2,265,478	$ 1,397,352	$ 16,376,538	$ 13,086,046
New Hampshire								
Firm Sales Pipeline Commodity Excld Hedge	$ 1,572,943	$ 1,535,110	$ 1,057,012	$ 847,137	$ 1,450,318	$ 1,471,667	$ 11,509,498	$ 7,934,188
Hedging (Gains) Losses	$ 46,208	$ 94,670	$ 116,228	$ 119,724	$ 94,055	$ 35,945	$ 523,383	$ 506,830
Storage	$ 201,390	$ 1,107,981	$ 1,963,268	$ 1,814,009	$ 946,838	$ -	$ 6,033,487	$ 6,033,487
Peaking	$ 4,580	$ 4,816	$ 12,601	$ 4,926	$ 5,129	$ 10,730	$ 70,206	$ 42,782
New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 1,825,122	$ 2,742,577	$ 3,149,110	$ 2,785,797	$ 2,496,340	$ 1,518,342	$ 18,136,574	$ 14,517,288
New Hampshire Inventory Finance Costs	$ 858	$ 1,415	$ 1,667	$ 1,441	$ 1,219	$ 694	$ 7,294	$ 7,294
Total New Hampshire Variable Costs	$ 1,825,980	$ 2,743,992	$ 3,150,777	$ 2,787,238	$ 2,497,559	$ 1,519,036	$ 18,143,868	$ 14,524,582
Northern Utilities								
Firm Sales Pipeline Commodity Excld Hedge	$ 2,994,861	$ 2,905,150	$ 2,011,379	$ 1,600,538	$ 2,765,867	$ 2,825,440	$ 21,928,980	$ 15,103,235
Hedging (Gains) Losses	$ 87,980	$ 179,160	$ 221,170	$ 226,200	$ 179,370	$ 69,010	$ 994,550	$ 962,890
Storage	$ 383,444	$ 2,096,823	$ 3,735,885	$ 3,427,295	$ 1,805,693	$ -	$ 11,449,140	$ 11,449,140
Peaking	$ 8,721	$ 9,114	$ 23,979	$ 9,307	$ 9,781	$ 20,600	$ 133,875	$ 81,502
Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Northern Commodity Costs	$ 3,475,006	$ 5,190,247	$ 5,992,413	$ 5,263,340	$ 4,760,711	$ 2,915,050	$ 34,506,545	$ 27,596,767
Northern Inventory Finance Costs	$ 1,633	$ 2,674	$ 3,171	$ 2,718	$ 2,326	$ 1,339	$ 13,861	$ 13,861
Total Northern Variable Costs	$ 3,476,639	$ 5,192,921	$ 5,995,584	$ 5,266,058	$ 4,763,037	$ 2,916,388	$ 34,520,406	$ 27,610,627

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	Company Analysis
55	New Hampshire	NH Schedule 10B, LN 33 / 10
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
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

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

Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
Inventory Finance Charge	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	
Storage	$ 1,637	$ 1,586	$ 1,274	$ 766	$ 260	$ -	$ 12,504	
Peaking	$ 115	$ 115	$ 113	$ 112	$ 113	$ 114	$ 1,357	
Total	$ 1,752	$ 1,701	$ 1,387	$ 878	$ 373	$ 114	$ 13,861	
Inventory Finance Charge Allocation by Jurisdiction								
Maine	$ 832	$ 802	$ 658	$ 413	$ 177	$ 55	$ 6,567	
New Hampshire	$ 920	$ 899	$ 729	$ 465	$ 196	$ 59	$ 7,294	
Total	$ 1,752	$ 1,701	$ 1,387	$ 878	$ 373	$ 114	$ 13,861	
Inventory Finance Charge Allocation by Month								
Maine								
Firm Sales Normal Remaining Sendout	239,969	389,464	465,444	395,153	342,532	199,341	2,031,904	2,031,904
Monthly % Sendout of Total Winter	11.81%	19.17%	22.91%	19.45%	16.86%	9.81%	100.00%	100.00%
ME Allocated Inventory Finance Charge	$ 776	$ 1,259	$ 1,504	$ 1,277	$ 1,107	$ 644	$ 6,567	$ 6,567
New Hampshire								
Firm Sales Normal Remaining Sendout	265,328	437,644	515,502	445,850	377,123	214,772	2,256,218	2,256,218
Monthly % Sendout of Total Winter	11.76%	19.40%	22.85%	19.76%	16.71%	9.52%	100.00%	100.00%
NH Allocated Inventory Finance Charge	$ 858	$ 1,415	$ 1,667	$ 1,441	$ 1,219	$ 694	$ 7,294	$ 7,294

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**	
95		
96		
97		
98	**Inventory Finance Charge**	
99	Storage	"Schedule 14 - Carrying Costs"
100	Peaking	"Schedule 14 - 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	Company Analysis
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	NH Schedule 10B, LN 80 / 10
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 - NEW HAMPSHIRE DIVISION
Supporting Detail to Proposed Tariff Sheets
Average Cost of Gas Calculation

		Winter	Summer	Total	
1	Demand	$ 15,264,073	$ 978,177	$ 16,242,250	Schedule 1A, LN 80
2	Commodity	$ 14,524,582	$ 3,619,286	$ 18,143,868	Schedule 1B, LN 43
3	Total	$ 29,788,654	$ 4,597,463	$ 34,386,118	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,614,458	7,466,573	36,081,030	Schedule 10B, LN 11
6	Forecasted Residential Sales (Therms)	13,532,174	3,440,019	16,972,192	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.5334	$0.1310		LN 1 / LN 5
9	Average Commodity Rate	$0.5076	$0.4847		LN 2 / LN 5
10	Average Rate	$1.0410	$0.6157		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 7,640,218	$ 469,673	$ 8,109,891	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 7,218,592	$ 450,642	$ 7,669,234	LN 8 * LN 6
15	**Demand Reallocation:**	$ 421,627	$ 19,030	$ 440,657	LN 13 - LN 14
16	**HLF Allocation**	$ 46,426	$ 5,388	$ 51,814	LN 15 * LN 20
17	**LLF Allocation**	$ 375,201	$ 13,642	$ 388,843	LN 15 * LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	11.01%	28.31%		Schedule 10A, LN 173
21	LLF	88.99%	71.69%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 6,863,160	$ 1,670,655	$ 8,533,815	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 6,868,876	$ 1,667,377	$ 8,536,253	LN 6 * LN 9
25	**Commodity Reallocation:**	$ (5,716)	$ 3,277	$ (2,438)	LN 23 - LN 24
26	**HLF Allocation**	$ (1,018)	$ 1,427	$ 409	LN 25 / LN 30
27	**LLF Allocation**	$ (4,698)	$ 1,851	$ (2,847)	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	17.81%	43.53%		Schedule 10C, LN 143
31	LLF	82.19%	56.47%		Schedule 10C, LN 144

Schedule 24

Northern Utilities, Inc.
Current Short-Term Debt Limit
($ in thousands)

NU Short-Term Debt Limit Calculation (11/1/11 - 10/31/2012)

Fuel Financing Purposes			
NU ME winter gas costs		28,016	
NU NH winter gas costs		31,904	
	Total	59,920	
30% of total winter gas costs		17,976	(a)
Non-Fuel Financing Purposes			
Estimated net utility plant @ 12/31/11 before plant acquisition adjustment		192,851	
15% of Net Utility Plant		28,928	(b)
Short-Term Debt Limit			
Short Term Debt Limit		**46,904**	(a) + (b)