Revised Schedule 1A

Allocation of Northern Fixed Capacity Costs

To New Hampshire and Maine

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	$ 3,399,789
3	Storage	$ 16,499,761
4	Peaking	$ 866,963
5	Total Gross Demand Cost	$ 20,766,513
6		
7	Capacity Assignment Demand Revenue Estimate	$ 3,574,514
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 20,766,513
9	Capacity Assignment as % of Total Gross Demand Cost	17.21%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 585,201
14	Storage	$ 2,840,083
15	Peaking	$ 149,229
16	Total Capacity Assignment Credit	$ 3,574,514
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,814,588
21	Storage	$ 13,659,678
22	Peaking	$ 717,734
23	Total Net Demand Cost (Less Capacity Assignment)	$ 17,191,999
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	13,681
28	Less 17.21% NH Transp. Capacity Assignment	(2,355)
29	Net Pipeline MDQ	11,326
30		
31	Net Pipeline MDQ	11,326
32	Less: Firm Sales Base Use	3,475
33	Remaining Pipeline MDQ	7,851
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$248.51
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,814,588
40	Less: Base Pipeline Use	$ 863,483
41	Remaining Pipeline Use	$ 1,951,104

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 17.21% 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

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

All Months	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
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
Rank	5	3	1	2	4	6	
% Max Month	51.47%	84.90%	100.00%	86.49%	73.16%	41.66%	
PR	1.96%	3.91%	13.51%	0.80%	5.42%	4.75%	
CumPR	8.45%	17.78%	32.09%	18.58%	13.87%	6.48%	97.24%

Peak Months Only	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
Remaining Load for Peak Months Only	2,653,282	4,376,435	5,155,015	4,458,499	3,771,225	2,147,722	
Rank	5	3	1	2	4	6	
% Max Month	51.47%	84.90%	100.00%	86.49%	73.16%	41.66%	
PR	1.96%	3.91%	13.51%	0.80%	5.42%	6.94%	
CumPR	8.91%	18.24%	32.55%	19.04%	14.33%	6.94%	100.00%

DEMAND COST PR ALLOCATORS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	50.00%
Pipeline - Remaining	8.45%	17.78%	32.09%	18.58%	13.87%	6.48%	97.24%
Storage & Peaking	8.45%	17.78%	32.09%	18.58%	13.87%	6.48%	97.24%
Capacity Release	8.91%	18.24%	32.55%	19.04%	14.33%	6.94%	100.00%
Interr. Margins & Off Sys Sales	8.91%	18.24%	32.55%	19.04%	14.33%	6.94%	100.00%

DEMAND COSTS ALLOCATED TO MONTHS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
Pipeline - Base	$ 71,957	$ 71,957	$ 71,957	$ 71,957	$ 71,957	$ 71,957	$ 431,742
Pipeline - Remaining	$ 164,772	$ 346,909	$ 626,061	$ 362,439	$ 270,554	$ 126,503	$ 1,897,237
Total Pipeline	$ 236,729	$ 418,866	$ 698,018	$ 434,396	$ 342,511	$ 198,460	$ 2,328,979
Storage & Peaking	$ 1,214,184	$ 2,556,321	$ 4,613,353	$ 2,670,759	$ 1,993,674	$ 932,181	$ 13,980,472
Adjustments to Demand Cost							
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)
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Direct Demand Costs	$ 1,307,324	$ 2,681,077	$ 4,786,567	$ 2,798,212	$ 2,105,177	$ 1,018,678	$ 14,697,036

Indirect Demand Costs/(Credits)
Miscellaneous Overhead
Local Production & Storage
Subtotal

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

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

	All Months	Total	Winter	Summer
44				
45	**All Months**	**Total**	**Winter**	**Summer**
46	Remaining Load for All Months	23,718,727	22,562,178	1,156,549
47	Rank			
48	% Max Month			
49	PR	32.09%		
50	CumPR	100.00%	97.24%	2.76%
51				
52	**Peak Months Only**	**Total**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only	22,562,178		
54	Rank			
55	% Max Month			
56	PR	32.55%		
57	CumPR	100.00%	100.00%	0.00%
58				

59 **DEMAND COST PR ALLOCATORS**

		Total	Winter	Summer
60		**Total**	**Winter**	**Summer**
61	Pipeline - Base	100.00%	50.00%	50.00%
62	Pipeline - Remaining	100.00%	97.24%	2.76%
63	Storage & Peaking	100.00%	97.24%	2.76%
64	Capacity Release	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	100.00%	100.00%	0.00%
66				

67 **DEMAND COSTS ALLOCATED TO MONTHS**

		Total	Winter	Summer	Winter	Summer
68		**Total**	**Winter**	**Summer**	**Winter**	**Summer**
69	Pipeline - Base	$ 863,483	$ 431,742	$ 431,742	50.00%	50.00%
70	Pipeline - Remaining	$ 1,951,104	$ 1,897,237	$ 53,867	97.24%	2.76%
71	Total Pipeline	$ 2,814,588	$ 2,328,979	$ 485,609	82.75%	17.25%
72						
73	Storage & Peaking	$ 14,377,412	$ 13,980,472	$ 396,939	97.24%	2.76%
74						
75	Adjustments to Demand Cost					
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	($1,612,415)	$ (1,612,415)	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -		
79						
80	Total Direct Demand Costs	$ 15,579,584	$ 14,697,036	$ 882,548	94.34%	5.66%
81						
82	Indirect Demand Costs/(Credits)					
83	Miscellaneous Overhead	$ 440,825	$ 349,601	$ 91,224	79.31%	20.69%
84	Local Production & Storage	$ 349,700	$ 349,700	$ -	100.00%	0.00%
85	Subtotal	$ 790,525	$ 699,301	$ 91,224	88.46%	11.54%

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

42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**	
43	(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)	
44		
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	Adjustments to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	LN 64 * Page 6, LN 7
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

Revised Schedule 1B

Commodity Costs

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	23,024,066	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	36,426,674	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	36,426,674	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	345,643	271,596
11	Percent Difference	0.94%	0.94%	0.94%	0.94%	0.94%	0.95%	0.95%	0.94%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 1,435,508	$ 1,434,090	$ 996,881	$ 801,031	$ 1,374,257	$ 1,387,276	$ 10,774,966	$ 7,429,043
15	New Hampshire Hedging (Gains) Losses	$ 69,938	$ 130,433	$ 157,834	$ 161,876	$ 126,592	$ 56,743	$ 742,762	$ 703,414
16	New Hampshire Total Storage	$ 200,573	$ 1,104,241	$ 1,959,235	$ 1,810,354	$ 946,895	$ -	$ 6,021,299	$ 6,021,299
17	New Hampshire Total Peaking	$ 4,530	$ 4,731	$ 12,297	$ 4,793	$ 4,970	$ 10,302	$ 67,752	$ 41,623
18	New Hampshire Inventory Finance Charge	$ 839	$ 1,383	$ 1,629	$ 1,409	$ 1,192	$ 679	$ 7,131	$ 7,131
19	Total New Hampshire Sales Variable Costs	$ 1,711,388	$ 2,674,879	$ 3,127,876	$ 2,779,463	$ 2,453,906	$ 1,454,999	$ 17,613,910	$ 14,202,510
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,641,450	$ 2,544,446	$ 2,970,042	$ 2,617,587	$ 2,327,314	$ 1,398,257	$ 16,871,148	$ 13,499,096
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 1,711,388	$ 2,674,879	$ 3,127,876	$ 2,779,463	$ 2,453,906	$ 1,454,999	$ 17,613,910	$ 14,202,510
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	0.4425	0.4775	0.5282	0.5480	0.4986	0.4371	$ 0.4680	$ 0.4785
27	New Hampshire Hedging (Gains) Losses	0.0216	0.0434	0.0836	0.1107	0.0459	0.0179	$ 0.0323	$ 0.0453
28	New Hampshire Storage Excld Inventory Finance Costs	0.4515	0.4520	0.4528	0.4529	0.4542	0.0000	$ 0.4529	$ 0.4529
29	New Hampshire Peaking Excld Inventory Finance Costs	0.6390	0.6419	0.6777	0.6939	0.6795	0.6339	$ 0.6365	$ 0.6599
30	New Hampshire Inventory Finance Costs per Dth Stor and P	0.0019	0.0006	0.0004	0.0004	0.0006	0.0418	$ 0.0005	$ 0.0005
31	Weighted Average Cost per Dth Sendout	0.4631	0.4905	0.5019	0.5085	0.5061	0.4561	$ 0.4835	$ 0.4917
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	$ 461,221	$ 514,377	$ 568,916	$ 552,224	$ 537,054	$ 455,629	$ 5,935,926	$ 3,089,421
38	Base Hedging Commodity Cost	$ 22,471	$ 46,783	$ 90,075	$ 111,596	$ 49,472	$ 18,636	$ 366,215	$ 339,033
39	Remaining Commodity Excld Hedging	$ 1,180,229	$ 2,030,069	$ 2,401,127	$ 2,065,363	$ 1,790,260	$ 942,627	$ 10,935,223	$ 10,409,675
40	Remaining Hedging Commodity	$ 47,467	$ 83,649	$ 67,759	$ 50,280	$ 77,120	$ 38,107	$ 376,547	$ 364,382
41	Total Commodity Excld Hedging	$ 1,641,450	$ 2,544,446	$ 2,970,042	$ 2,617,587	$ 2,327,314	$ 1,398,257	$ 16,871,148	$ 13,499,096
42	Total Hedging	$ 69,938	$ 130,433	$ 157,834	$ 161,876	$ 126,592	$ 56,743	$ 742,762	$ 703,414
43	Total Commodity (Incl Hedging)	$ 1,711,388	$ 2,674,879	$ 3,127,876	$ 2,779,463	$ 2,453,906	$ 1,454,999	$ 17,613,910	$ 14,202,510

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

Revised Schedule 2

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
Tenn Zone 4 Spot	$701,757	168,345	$4.169
Tennessee Production	$6,378,322	1,495,554	$4.265
Chicago	$806,740	188,922	$4.270
Washington 10 Storage	$10,496,263	2,324,515	$4.515
Niagara	$51,593	11,194	$4.609
Tennessee Storage	$929,771	198,563	$4.683
PNGTS	$1,009,678	181,363	$5.567
Lewiston Baseload	$5,193,684	911,000	$5.701
LNG	$79,291	12,018	$6.598
Total System	$25,647,099	5,491,472	$4.670

Revised Schedule 3A

COG (Over)/Under Cumulative Recovery

Peak Period

Northern Utilities

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

Line			Summer						Winter						
	Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1		Apr-12	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
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								$1.0837	$1.0837	$1.0837	$1.0837	$1.0837	$1.0837	
9	Sales HLF Classes CGA								$0.9232	$0.9232	$0.9232	$0.9232	$0.9232	$0.9232	
10	Sales LLF Classes CGA								$1.1166	$1.1166	$1.1166	$1.1166	$1.1166	$1.1166	
11	Revenues														
12	Residential Heat & Non Heat								$ (1,875,894)	$ (2,769,499)	$ (3,164,652)	$ (2,775,121)	$ (2,461,346)	$ (1,618,304)	$ (14,664,817)
13	Sales HLF Classes								$ (302,276)	$ (444,135)	$ (507,991)	$ (446,378)	$ (396,040)	$ (262,285)	$ (2,359,104)
14	Sales LLF Classes								$ (1,789,262)	$ (2,641,599)	$ (3,018,502)	$ (2,646,961)	$ (2,347,676)	$ (1,543,568)	$ (13,987,569)
15	Total Sales Revenues								$ (3,967,432)	$ (5,855,233)	$ (6,691,145)	$ (5,868,459)	$ (5,205,061)	$ (3,424,158)	$ (31,011,489)
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		$ 193,530	$ 193,530	$ 193,530	$ 193,530	$ 193,530	$ 193,530	$ 193,462	$ 193,462	$ 195,781	$ 195,781	$ 195,781	$ 193,530	$ 2,328,979
22	Storage		$ 702,802	$ 702,802	$ 702,802	$ 702,802	$ 702,802	$ 702,802	$ 1,627,657	$ 1,627,657	$ 1,696,806	$ 1,696,806	$ 1,696,806	$ 702,802	$ 13,265,346
23	Peaking		$ 41,836	$ 41,836	$ 41,836	$ 41,836	$ 41,836	$ 41,836	$ 81,013	$ 81,013	$ 81,013	$ 81,013	$ 81,013	$ 41,836	$ 697,918
24	Total Demand Costs		$ 938,168	$ 938,168	$ 938,168	$ 938,168	$ 938,168	$ 938,168	$ 1,902,132	$ 1,902,132	$ 1,973,600	$ 1,973,600	$ 1,973,600	$ 938,168	$ 16,292,243
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™								$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 14,141,773
28	NYMEX Price Used for Forecast								$ 3.5410	$ 3.8360	$ 4.0060	$ 4.0280	$ 3.9940	$ 3.9810	
29	NYMEX Price Used for Update								$ 3.5410	$ 3.8360	$ 4.0060	$ 4.0280	$ 3.9940	$ 3.9810	
30	Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
31	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
32	Updated Pipeline Costs								$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 4.42	$ 4.78	$ 5.28	$ 5.48	$ 4.99	$ 4.37	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	
37	New Hampshire Allocated Percentage								52.52%	52.84%	52.55%	52.93%	52.44%	52.09%	
38	NH Updated Pipeline Costs								$ 1,435,508	$ 1,434,090	$ 996,881	$ 801,031	$ 1,374,257	$ 1,387,276	$ 7,429,043
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								$ 3.5410	$ 3.8360	$ 4.0060	$ 4.0280	$ 3.9940	$ 3.9810	
44	NYMEX Price Used for Update								$ 3.5410	$ 3.8360	$ 4.0060	$ 4.0280	$ 3.9940	$ 3.9810	
45	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ 133,160	$ 246,840	$ 300,340	$ 305,840	$ 241,420	$ 108,940	$ 1,336,540
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								$ 69,938	$ 130,433	$ 157,834	$ 161,876	$ 126,592	$ 56,743	$ 703,414

Peak Period

Northern Utilities

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

			Summer						Winter						
	Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1		Apr-12	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
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								$ 3.5410	$ 3.8360	$ 4.0060	$ 4.0280	$ 3.9940	$ 3.9810	
53	NYMEX Price Used for Update								$ 3.5410	$ 3.8360	$ 4.0060	$ 4.0280	$ 3.9940	$ 3.9810	
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								$ 1,435,508	$ 1,434,090	$ 996,881	$ 801,031	$ 1,374,257	$ 1,387,276	$ 7,429,043
60	Hedging (Gain)/Loss Estimate								$ 69,938	$ 130,433	$ 157,834	$ 161,876	$ 126,592	$ 56,743	$ 703,414
61	Storage								$ 200,573	$ 1,104,241	$ 1,959,235	$ 1,810,354	$ 946,895	$ -	$ 6,021,299
62	Peaking								$ 4,530	$ 4,731	$ 12,297	$ 4,793	$ 4,970	$ 10,302	$ 41,623
63	Total Commodity Costs								$ 1,710,549	$ 2,673,495	$ 3,126,246	$ 2,778,054	$ 2,452,714	$ 1,454,321	$ 14,195,380
64	Inventory Finance Charge		$ 169	$ 386	$ 615	$ 830	$ 927	$ 917	$ 927	$ 906	$ 734	$ 467	$ 195	$ 57	$ 7,131
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		$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 34,573	$ 414,873
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		$ (266,309)	$ (266,309)	$ (277,468)	$ (277,468)	$ (277,468)	$ (256,793)	$ (423,634)	$ (423,634)	$ (423,634)	$ (423,634)	$ (423,634)	$ (245,634)	$ (3,985,617)
70	NH AMA Revenue		$ (85,760)	$ (85,760)	$ (85,760)	$ (85,760)	$ (85,760)	$ (85,760)	$ (166,157)	$ (166,157)	$ (166,157)	$ (166,157)	$ (166,157)	$ (85,760)	$ (1,431,100)
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		$ (101,955)	$ (101,955)	$ (107,198)	$ (107,198)	$ (107,198)	$ (97,483)	$ (172,637)	$ (172,637)	$ (172,637)	$ (172,637)	$ (172,637)	$ (92,239)	$ (1,578,408)

Peak Period

Northern Utilities

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

			Summer						Winter						
	Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1		Apr-12	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
73															
74	**Total Anticipated Direct Cost of Gas**		$ 836,383	$ 836,599	$ 831,585	$ 831,801	$ 831,897	$ 841,602	$ 3,440,973	$ 4,403,897	$ 4,927,944	$ 4,579,484	$ 4,253,873	$ 2,300,307	$ 28,916,345
75			Winter						Summer						
76			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Apr-12	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
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ 836,383	$ 836,599	$ 831,585	$ 831,801	$ 831,897	$ 841,602	$ 3,440,973	$ 4,403,897	$ 4,927,944	$ 4,579,484	$ 4,253,873	$ 2,300,307	$ 28,916,345
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		$ 689	$ 689	$ 685	$ 685	$ 685	$ 693	$ 2,835	$ 3,629	$ 4,061	$ 3,773	$ 3,505	$ 1,895	$ 23,827
82	Beginning Period Working Capital Balance		$ (35,228)	$ (34,602)	$ (33,975)	$ (33,351)	$ (32,726)	$ (32,100)	$ (31,464)	$ (28,683)	$ (25,104)	$ (21,085)	$ (17,347)	$ (13,870)	
83	End of Period Working Capital Allowance		$ (34,539)	$ (33,913)	$ (33,290)	$ (32,666)	$ (32,041)	$ (31,406)	$ (28,629)	$ (25,055)	$ (21,043)	$ (17,312)	$ (13,841)	$ (11,974)	
84	Interest		$ (64)	$ (62)	$ (61)	$ (60)	$ (59)	$ (58)	$ (55)	$ (49)	$ (42)	$ (35)	$ (28)	$ (24)	$ (597)
85	End of period with Interest	$ (35,228)	$ (34,602)	$ (33,975)	$ (33,351)	$ (32,726)	$ (32,100)	$ (31,464)	$ (28,683)	$ (25,104)	$ (21,085)	$ (17,347)	$ (13,870)	$ (11,998)	
86	Bad Debt														
87	Total Anticipated Direct Cost of Gas		$ -						$ 3,440,973	$ 4,403,897	$ 4,927,944	$ 4,579,484	$ 4,253,873	$ 2,300,307	$ 23,906,478
88	Prior Period Over/Under Collection	$ 1,935	$ -	$ -	$ -	$ -	$ -	$ -							$ 1,935
89	Bad Debt Allowance		$ -						$ 54,329	$ 69,533	$ 77,807	$ 72,305	$ 67,164	$ 36,319	$ 377,457
90	Beginning Period Bad Debt Balance		$ 1,935	$ 1,939	$ 1,942	$ 1,946	$ 1,949	$ 1,953	$ 1,956	$ 56,339	$ 126,037	$ 204,145	$ 276,888	$ 344,617	
91	End of Period Bad Debt Balance		$ 1,935	$ 1,939	$ 1,942	$ 1,946	$ 1,949	$ 1,953	$ 56,285	$ 125,871	$ 203,844	$ 276,450	$ 344,052	$ 380,937	
92	Interest		$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 53	$ 166	$ 301	$ 438	$ 566	$ 661	$ 2,205
93	End of Period Bad Debt Balance with Interest	$ 1,935	$ 1,939	$ 1,942	$ 1,946	$ 1,949	$ 1,953	$ 1,956	$ 56,339	$ 126,037	$ 204,145	$ 276,888	$ 344,617	$ 381,598	
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	$ 1,812,546	$ 2,653,210	$ 3,490,387	$ 4,329,304	$ 5,169,847	$ 6,021,635	$ 5,622,323	$ 4,296,564	$ 2,656,241	$ 1,487,588	$ 654,900	
98	Net Costs - Revenues		$ 836,383	$ 836,599	$ 831,585	$ 831,801	$ 831,897	$ 841,602	$ (409,909)	$ (1,334,786)	$ (1,646,651)	$ (1,172,424)	$ (834,638)	$ (1,007,301)	
99	Ending Balance before Interest		$ 1,810,011	$ 2,649,146	$ 3,484,795	$ 4,322,187	$ 5,161,202	$ 6,011,449	$ 5,611,725	$ 4,287,537	$ 2,649,913	$ 1,483,816	$ 652,950	$ (352,401)	
100	Average Balance		$ 1,391,819	$ 2,230,846	$ 3,069,003	$ 3,906,287	$ 4,745,253	$ 5,590,648	$ 5,816,680	$ 4,954,930	$ 3,473,239	$ 2,070,029	$ 1,070,269	$ 151,249	
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		$ 2,536	$ 4,064	$ 5,591	$ 7,117	$ 8,645	$ 10,186	$ 10,598	$ 9,027	$ 6,328	$ 3,771	$ 1,950	$ 276	$ 70,090
103	Ending Balance Incl Interest Expense	$ 973,628	$ 1,812,546	$ 2,653,210	$ 3,490,387	$ 4,329,304	$ 5,169,847	$ 6,021,635	$ 5,622,323	$ 4,296,564	$ 2,656,241	$ 1,487,588	$ 654,900	$ (352,126)	
104	**Total Over/Under Collection Ending Balance**		$ 1,779,883	$ 2,621,177	$ 3,458,981	$ 4,298,527	$ 5,139,700	$ 5,992,127	$ 5,649,978	$ 4,397,498	$ 2,839,300	$ 1,747,129	$ 985,647	$ 17,474	
105															$ -
106															
107	**Total Indirect Cost of Gas**	$ 940,335	$ 3,165	$ 4,695	$ 6,219	$ 7,746	$ 9,275	$ 10,825	$ 184,311	$ 198,856	$ 205,004	$ 196,803	$ 189,707	$ 155,678	$ 2,112,619
108															
109	**Total Cost of Gas**	$ 940,335	$ 839,548	$ 841,294	$ 837,804	$ 839,546	$ 841,173	$ 852,427	$ 3,625,283	$ 4,602,753	$ 5,132,948	$ 4,776,288	$ 4,443,580	$ 2,455,985	$ 31,028,963
110															
111	**Total Interest**	$ -	$ 2,476	$ 4,006	$ 5,534	$ 7,060	$ 8,590	$ 10,131	$ 10,596	$ 9,145	$ 6,586	$ 4,174	$ 2,487	$ 913	$ 71,698

Revised Schedule 3B

Bad Debt Calculation

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	$	35,893	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

Revised Schedule 5A

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2011 through October 31, 2012			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,758,849	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 30,261,073	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	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	$ 39,468,889	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	$ 24.4547	12	Line 7 of Page 2, Att to Sch 5A	$ 112,614	$ 1,351,367
Tennessee	5083	FT-A	No	8,550	Zone L	Zone 6	$ 21.6916	12	Line 8 of Page 2, Att to Sch 5A	$ 185,463	$ 2,225,558
Tennessee	5265	FT-A	No	2,653	Zone 4	Zone 6	$ 8.4896	12	Line 9 of Page 2, Att to Sch 5A	$ 22,523	$ 270,275
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 10,460	$ 125,521
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 16,561	$ 198,727
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 6,911	$ 82,937
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 31,745	$ 380,937
Tennessee	46314	FT-A	No	950	Zone 5	Zone 6	$ 7.4396	5	Line 10 of Page 2, Att to Sch 5A	$ 7,068	$ 35,338
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	$ 30.0972	2	Line 18 of Page 2, Att to Sch 5A	$ 1,023,305	$ 2,046,610
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 35.4197	10	Line 18 of Page 2, Att to Sch 5A	$ 1,204,270	$ 12,042,698
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 12.3344	2	Line 19 of Page 2, Att to Sch 5A	$ 73,229	$ 146,459
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 13.5608	10	Line 19 of Page 2, Att to Sch 5A	$ 80,510	$ 805,105
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 $ 40,323,782

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%	$ 1,351,367	$ 1,351,367	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 2,225,558	$ 2,225,558	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 270,275	$ -	$ 270,275	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 125,521	$ 125,521	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 198,727	$ 198,727	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 82,937	$ 82,937	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 380,937	$ 380,937	$ -	$ -
Tennessee	46314	950	950	-		100%	0%	0%	$ 35,338	$ 35,338	$ -	$ -
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%	$ 2,046,610	$ -	$ 2,046,610	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 12,042,698	$ -	$ 12,042,698	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 146,459	$ 146,459	$ -	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 805,105	$ 805,105	$ -	$ -
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									$ 40,323,782	$ 8,758,849	$ 30,261,073	$ 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	$ 0.0211	$ 1.5400	12	Line 1 of Page 3, Att to Sch 5A	$ 65,664	$ 78,411	$ 144,075
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 $ 3,036,846

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Revised Attachment to Schedule 5A

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for October 10, 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	$3.541	$3.836	$4.006	$4.028	$3.994	$3.981

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	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547
8	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916
9	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896
10	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396
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 45A Page 26	$ 30.0972	$ 30.0972	$ 35.4197	$ 35.4197	$ 35.4197	$ 35.4197
19	TransCanada	FT	Parkway	Iroquois		Page 26	$ 12.3344	$ 12.3344	$ 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 19	$ 0.2751	$ 0.2751	$ 0.2751	$ 0.2751	$ 0.2751	$ 0.2751
32	Tennessee	FT-A	Zone 0	Zone 6		Page 19	$ 0.3124	$ 0.3124	$ 0.3124	$ 0.3124	$ 0.3124	$ 0.3124
33	Tennessee	FT-A	Zone L	Zone 4		Page 19	$ 0.2339	$ 0.2339	$ 0.2339	$ 0.2339	$ 0.2339	$ 0.2339
34	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 0.2723	$ 0.2723	$ 0.2723	$ 0.2723	$ 0.2723	$ 0.2723
35	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073
36	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811
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 20, 22	$ 0.0211	$ 1.5400	$ 0.0087	0.00%	$ 0.0087	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%

Tennessee Gas Pipeline Company
Settlement Rates - Base Reservation and Commodity

Line No.		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
	Rate Schedule FT-A, FT-G, NET, NET-284								
	Reservation								
1	Zone 0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
2	Zone L		$5.0941						
3	Zone 1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
4	Zone 2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
5	Zone 3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
6	Zone 4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
7	Zone 5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
8	Zone 6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846
	Commodity	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
9	Zone 0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2751	$0.2625	$0.3124
10	Zone L		$0.0012						
11	Zone 1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2339	$0.2385	$0.2723
12	Zone 2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0757	$0.1214	$0.1345
13	Zone 3	$0.0207		$0.0169	$0.0026	$0.0002	$0.1012	$0.1400	$0.1528
14	Zone 4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0468	$0.0662	$0.1073
15	Zone 5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0659	$0.0653	$0.0811
16	Zone 6	$0.0346		$0.0300	$0.0143	$0.0163	$0.1014	$0.0549	$0.0334
	Minimum Commodity				**Delivery Zone**				
		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
17	Zone 0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
18	Zone L		$0.0012						
19	Zone 1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
20	Zone 2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
21	Zone 3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
22	Zone 4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
23	Zone 5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
24	Zone 6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020
	Rate Schedule FT-GS	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
25	Zone 0	$0.3183		$0.6758	$0.9131	$0.9332	$1.2806	$1.3301	$1.6524
26	Zone L		$0.2803						
27	Zone 1	$0.4812		$0.4652	$0.6247	$0.8843	$1.0901	$1.2048	$1.4609
28	Zone 2	$0.9121		$0.6150	$0.3140	$0.2949	$0.4521	$0.6412	$0.8061
29	Zone 3	$0.9320		$0.4961	$0.3180	$0.2262	$0.4524	$0.7796	$0.8918
30	Zone 4	$1.1835		$1.0881	$0.4123	$0.6265	$0.3465	$0.3908	$0.5725
31	Zone 5	$1.4108		$0.9954	$0.4336	$0.5255	$0.3995	$0.3779	$0.4887
32	Zone 6	$1.6338		$1.1438	$0.7790	$0.8593	$0.6970	$0.3651	$0.3010
	Rate Schedule IT and PTR	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
33	Zone 0	$0.1923		$0.4101	$0.5549	$0.5687	$0.8784	$0.9031	$1.1164
34	Zone L		$0.1687						
35	Zone 1	$0.2904		$0.2823	$0.3807	$0.5377	$0.7476	$0.8183	$0.9854
36	Zone 2	$0.5539		$0.3725	$0.1889	$0.1780	$0.3015	$0.4333	$0.5375
37	Zone 3	$0.5675		$0.3044	$0.1918	$0.1358	$0.3119	$0.5238	$0.5962
38	Zone 4	$0.7201		$0.6611	$0.2508	$0.3801	$0.2266	$0.2610	$0.3864
39	Zone 5	$0.8578		$0.6075	$0.2641	$0.3200	$0.2661	$0.2528	$0.3257
40	Zone 6	$0.9941		$0.6983	$0.4731	$0.5221	$0.4587	$0.2410	$0.1940

Tennessee Gas Pipeline Company
Settlement Rates - Base Reservation and Commodity

Rate Schedule FT-BH

Reservation

Line No.		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
1	Zone 0	$2.8752							
2	Zone L		$2.5471						
3	Zone 1	$4.3530		$4.1707					
4	Zone 2	$8.1703		$5.5327	$2.8542				
5	Zone 3	$8.3157		$4.3724	$2.8777	$2.0625			
6	Zone 4	$10.5713		$9.7420	$3.6824	$5.6215	$2.7350		
7	Zone 5	$12.6141		$8.8492	$3.8652	$4.6871	$3.0440	$2.8522	
8	Zone 6	$14.5923		$10.1638	$6.9776	$7.6925	$5.4346	$2.8307	$2.4423

Commodity

Line No.		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
9	Zone 0	$0.0505							
10	Zone L		$0.0431						
11	Zone 1	$0.0758		$0.0767					
12	Zone 2	$0.1510		$0.0996	$0.0481				
13	Zone 3	$0.1574		$0.0888	$0.0499	$0.0341			
14	Zone 4	$0.1988		$0.1806	$0.0692	$0.1029	$0.0918		
15	Zone 5	$0.2358		$0.1711	$0.0735	$0.0888	$0.1159	$0.1122	
16	Zone 6	$0.2745		$0.1971	$0.1290	$0.1428	$0.1907	$0.1014	$0.0735

Rate Schedule FT-A Extended Delivery Service / Extended Receipt Service

Reservation

Line No.		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
17	Zone 0			$0.3986	$0.5372	$0.5468	$0.6033	$0.6406	$0.8040
18	Zone L								
19	Zone 1	$0.2862			$0.3660	$0.5198	$0.5137	$0.5798	$0.7131
20	Zone 2	$0.5372		$0.3638		$0.1752	$0.2258	$0.3119	$0.4030
21	Zone 3	$0.5468		$0.2875	$0.1892		$0.2107	$0.3838	$0.4434
22	Zone 4	$0.6951		$0.6406	$0.2421	$0.3696		$0.1948	$0.2791
23	Zone 5	$0.8294		$0.5819	$0.2541	$0.3082	$0.2002		$0.2446
24	Zone 6	$0.9595		$0.6683	$0.4588	$0.5058	$0.3573	$0.1861	

Line No.			
25	**Park and Loan (PAL) Service**	$0.4154	
	Incremental Transportation Services	Reservation	Commodity
26	DOMAC (FT-A)	$2.9170	$0.0000
27	Stagecoach (FT-A)	$3.8448	$0.0000
28	ConneXion NY/NJ (FT-A)	$10.8058	$0.0000
29	Concord (FT-A)	$12.7436	$0.0000
30	Tewksbury (FT-IL)	$6.4374	$0.0000

Line No.	**Storage Services**	Deliverability	Capacity	Inj/With	Overrun
31	FS - PA	$2.8100	$0.0286	$0.0073	$0.3372
32	FS - MA	$1.5400	$0.0211	$0.0087	$0.1848
33	IS - PA		$0.1050	$0.0073	
34	IS - MA		$0.0846	$0.0087	

Canadian Fixed Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Demand Toll	$CAD / GJ	$ 10.16778	Page 3
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 1.03785	Page 2
4	Total Demand Toll	$CAD / GJ	$ 11.20563	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.0433	Page 27 of FXW-10
6	Total Demand Toll	$US / GJ	$ 11.6908	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Total Demand Toll	$US / Dth	$ 12.3344	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Demand Toll	$CAD / GJ	$ 22.70383	Page 4
12	Union Dawn Surcharge	$CAD / GJ	$ 0.09828	Page 3
13	Delivery Pressure Demand Toll	$CAD / GJ	$ 4.54054	Page 3
14	Total Demand Toll	$CAD / GJ	$ 27.34265	Sum Lines Above.
15	$CAD to $US	Ratio	1.0433	Page 27 of FXW-10
16	Total Demand Toll	$US / GJ	$ 28.5266	Line 13 times Line 14
17	GJ per Dth	Ratio	1.0551	
18	Total Demand Toll	$US / Dth	$ 30.0972	Line 15 divided by Line 16

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Transportation Tolls
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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	76,148	3,938,676	GJ	19.3333983638	$/GJ	0.0529682147	$/GJ
2	Transmission - Fixed	1,169,509	4,862,440,154	GJ-KM	0.2405190214	$/GJ-Km	0.0006589562	$/GJ-Km
3	Transmission - Variable	48,954	1,053,676,682,785	GJ-KM	-	$/GJ-Km	0.0000464601	$/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	4.46187	0.00722	0.1539
5	Union WDA	31.41463	0.06896	1.1018
6	Union NDA	12.30579	0.02546	0.4300
7	Union EDA	8.00131	0.01505	0.2781
8	KPUC EDA	7.70246	0.01412	0.2674
9	GMIT EDA	14.16801	0.02929	0.4951
10	Enbridge CDA	1.69730	0.00024	0.0560
11	Enbridge EDA	4.84530	0.00757	0.1669
12	Cornwall	10.94987	0.02165	0.3816
13	Philipsburg	14.44301	0.02974	0.5046

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	3.87336	0.00487	0.1322
15	Parkway to Goreway - CDA	2.39507	0.00144	0.0802
16	Parkway to Victoria Square #2 CDA	3.17490	0.00326	0.1077

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
17	Emerson - 1 (Viking)	0.09571	0.00000	0.0032
18	Emerson - 2 (Great Lakes)	0.14114	0.00000	0.0046
19	Dawn	0.08038	0.00000	0.0026
20	Niagara Falls	0.59443	0.00000	0.0195
21	Iroquois	1.03785	0.00000	0.0341
22	Chippawa	1.03444	0.00000	0.0340
23	East Hereford	4.54054	0.03226	0.1815

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

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	0.09828	0.00000	0.0032

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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) ($/GJ)	IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Parkway Belt	Centrat MDA	40.47278	0.09008	1.4207	1.5628
2	Union Parkway Belt	Union WDA	31.16449	0.06841	1.0930	1.2023
3	Union Parkway Belt	Nipigon WDA	27.37231	0.05971	0.9596	1.0556
4	Union Parkway Belt	Union NDA	12.30620	0.02546	0.4301	0.4731
5	Union Parkway Belt	Calstock NDA	20.74300	0.04435	0.7264	0.7990
6	Union Parkway Belt	Tunis NDA	15.52374	0.03225	0.5427	0.5970
7	Union Parkway Belt	GMIT NDA	11.69247	0.02319	0.4076	0.4484
8	Union Parkway Belt	Union SSMDA	18.35505	0.03881	0.6423	0.7065
9	Union Parkway Belt	Union NCDA	5.29747	0.00861	0.1828	0.2011
10	Union Parkway Belt	Union CDA	2.07011	0.00053	0.0686	0.0755
11	Union Parkway Belt	Enbridge CDA	3.14523	0.00350	0.1069	0.1176
12	Union Parkway Belt	Union EDA	8.15784	0.01535	0.2836	0.3120
13	Union Parkway Belt	Enbridge EDA	10.97773	0.02175	0.3827	0.4210
14	Union Parkway Belt	GMIT EDA	14.26643	0.02945	0.4985	0.5484
15	Union Parkway Belt	KPUC EDA	7.70246	0.01412	0.2673	0.2940
16	Union Parkway Belt	North Bay Junction	8.81626	0.01670	0.3065	0.3372
17	Union Parkway Belt	Enbridge SWDA	6.15853	0.01054	0.2130	0.2343
18	Union Parkway Belt	Union SWDA	6.36578	0.01079	0.2201	0.2421
19	Union Parkway Belt	Spruce	40.47278	0.09008	1.4207	1.5628
20	Union Parkway Belt	Emerson 1	38.02790	0.08441	1.3346	1.4681
21	Union Parkway Belt	Emerson 2	38.02790	0.08441	1.3346	1.4681
22	Union Parkway Belt	St. Clair	6.63616	0.01165	0.2299	0.2529
23	Union Parkway Belt	Dawn Export	6.15853	0.01054	0.2130	0.2343
24	Union Parkway Belt	Kirkwall	2.37697	0.00178	0.0799	0.0879
25	Union Parkway Belt	Niagara Falls	4.27106	0.00617	0.1466	0.1613
26	Union Parkway Belt	Chippawa	4.31896	0.00628	0.1483	0.1631
27	Union Parkway Belt	Iroquois	10.16778	0.01983	0.3541	0.3895
28	Union Parkway Belt	Cornwall	11.01681	0.02180	0.3840	0.4224
29	Union Parkway Belt	Napierville	14.09626	0.02894	0.4923	0.5415
30	Union Parkway Belt	Philipsburg	14.44621	0.02975	0.5047	0.5552
31	Union Parkway Belt	East Hereford	18.15642	0.03835	0.6353	0.6988
32	Union Parkway Belt	Welwyn	46.28071	0.10354	1.6251	1.7876
33	Union NCDA	Empress	56.87397	0.12803	1.9978	2.1976
34	Union NCDA	Transgas SSDA	48.16057	0.10875	1.6922	1.8614
35	Union NCDA	Centram SSDA	44.61612	0.09962	1.5664	1.7230
36	Union NCDA	Centram MDA	39.26096	0.08782	1.3786	1.5165
37	Union NCDA	Centrat MDA	36.78642	0.08147	1.2909	1.4200
38	Union NCDA	Union WDA	27.47814	0.05979	0.9632	1.0595
39	Union NCDA	Nipigon WDA	23.68595	0.05110	0.8298	0.9128
40	Union NCDA	Union NDA	8.61984	0.01685	0.3003	0.3303
41	Union NCDA	Calstock NDA	17.05665	0.03574	0.5965	0.6562
42	Union NCDA	Tunis NDA	11.83738	0.02364	0.4128	0.4541
43	Union NCDA	GMIT NDA	8.00632	0.01458	0.2778	0.3056
44	Union NCDA	Union SSMDA	22.04140	0.04742	0.7720	0.8492
45	Union NCDA	Union NCDA	1.61112	0.00000	0.0530	0.0583
46	Union NCDA	Union CDA	5.75646	0.00915	0.1985	0.2184
47	Union NCDA	Enbridge CDA	5.20928	0.00836	0.1797	0.1977
48	Union NCDA	Union EDA	9.89018	0.01945	0.3447	0.3792
49	Union NCDA	Enbridge EDA	11.86043	0.02382	0.4137	0.4551
50	Union NCDA	GMIT EDA	15.84503	0.03319	0.5541	0.6095
51	Union NCDA	KPUC EDA	9.52199	0.01840	0.3315	0.3647
52	Union NCDA	North Bay Junction	5.12991	0.00809	0.1768	0.1945
53	Union NCDA	Enbridge SWDA	9.84488	0.01915	0.3429	0.3772
54	Union NCDA	Union SWDA	10.05213	0.01940	0.3499	0.3849
55	Union NCDA	Spruce	36.78642	0.08147	1.2909	1.4200
56	Union NCDA	Emerson 1	39.62795	0.08806	1.3909	1.5300
57	Union NCDA	Emerson 2	39.62795	0.08806	1.3909	1.5300
58	Union NCDA	St. Clair	10.32252	0.02026	0.3597	0.3957
59	Union NCDA	Dawn Export	9.84488	0.01915	0.3429	0.3772
60	Union NCDA	Kirkwall	6.06332	0.01039	0.2097	0.2307
61	Union NCDA	Niagara Falls	7.95741	0.01478	0.2764	0.3040
62	Union NCDA	Chippawa	8.00531	0.01489	0.2781	0.3059
63	Union NCDA	Iroquois	11.79008	0.02368	0.4113	0.4524
64	Union NCDA	Cornwall	12.59522	0.02554	0.4396	0.4836
65	Union NCDA	Napierville	15.67466	0.03268	0.5480	0.6028
66	Union NCDA	Philipsburg	16.02462	0.03349	0.5603	0.6163
67	Union NCDA	East Hereford	19.73483	0.04209	0.6909	0.7600
68	Union NCDA	Welwyn	44.61612	0.09962	1.5664	1.7230
69	Union SSMDA	Empress	45.07892	0.10076	1.5828	1.7411
70	Union SSMDA	Transgas SSDA	36.36551	0.08147	1.2771	1.4048
71	Union SSMDA	Centram SSDA	32.82107	0.07234	1.1513	1.2664
72	Union SSMDA	Centram MDA	27.43845	0.06048	0.9626	1.0589
73	Union SSMDA	Centrat MDA	27.41259	0.05981	0.9610	1.0571
74	Union SSMDA	Union WDA	37.50337	0.08335	1.3164	1.4480
75	Union SSMDA	Nipigon WDA	40.51306	0.09017	1.4221	1.5643
76	Union SSMDA	Union NDA	29.05013	0.06427	1.0194	1.1213
77	Union SSMDA	Calstock NDA	37.48693	0.08316	1.3156	1.4472
78	Union SSMDA	Tunis NDA	32.26767	0.07106	1.1320	1.2452

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1	(i)	Union Dawn	Empress	53.99115	0.12142	1.8965	2.0862
2	(i)	Union Dawn	Transgas SSDA	45.27755	0.10213	1.5907	1.7498
3	(i)	Union Dawn	Centram SSDA	41.73330	0.09300	1.4651	1.6116
4	(i)	Union Dawn	Centram MDA	36.35048	0.08114	1.2762	1.4038
5	(i)	Union Dawn	Centrat MDA	36.32483	0.08047	1.2747	1.4022
6	(i)	Union Dawn	Union WDA	35.43270	0.07837	1.2433	1.3676
7	(i)	Union Dawn	Nipigon WDA	31.91972	0.07026	1.1197	1.2317
8	(i)	Union Dawn	Union NDA	16.85361	0.03600	0.5901	0.6491
9	(i)	Union Dawn	Calstock NDA	25.29041	0.05489	0.8864	0.9750
10	(i)	Union Dawn	Tunis NDA	20.07115	0.04279	0.7027	0.7730
11	(i)	Union Dawn	GMIT NDA	16.23988	0.03373	0.5676	0.6244
12	(i)	Union Dawn	Union SSMDA	13.80764	0.02827	0.4822	0.5304
13	(i)	Union Dawn	Union NCDA	9.84488	0.01915	0.3429	0.3772
14	(i)	Union Dawn	Union CDA	6.30424	0.01066	0.2180	0.2398
15	(i)	Union Dawn	Enbridge CDA	7.49321	0.01360	0.2600	0.2860
16	(i)	Union Dawn	Union EDA	12.70526	0.02589	0.4436	0.4880
17	(i)	Union Dawn	Enbridge EDA	15.52514	0.03229	0.5427	0.5970
18	(i)	Union Dawn	GMIT EDA	18.81384	0.03999	0.6585	0.7244
19	(i)	Union Dawn	KPUC EDA	12.24987	0.02466	0.4274	0.4701
20	(i)	Union Dawn	North Bay Junction	13.36368	0.02724	0.4666	0.5133
21	(i)	Union Dawn	Enbridge SWDA	1.61112	0.00000	0.0530	0.0583
22	(i)	Union Dawn	Union SWDA	1.81836	0.00025	0.0601	0.0661
23	(i)	Union Dawn	Spruce	36.32483	0.08047	1.2747	1.4022
24	(i)	Union Dawn	Emerson 1	33.48049	0.07387	1.1746	1.2921
25	(i)	Union Dawn	Emerson 2	33.48049	0.07387	1.1746	1.2921
26	(i)	Union Dawn	St. Clair	2.08875	0.00111	0.0698	0.0768
27	(i)	Union Dawn	Dawn Export	1.61112	0.00000	0.0530	0.0583
28	(i)	Union Dawn	Kirkwall	5.39268	0.00877	0.1861	0.2047
29	(i)	Union Dawn	Niagara Falls	7.62509	0.01394	0.2646	0.2911
30	(i)	Union Dawn	Chippawa	7.67300	0.01405	0.2664	0.2930
31	(i)	Union Dawn	Iroquois	14.71519	0.03038	0.5142	0.5656
32	(i)	Union Dawn	Cornwall	15.56423	0.03234	0.5440	0.5984
33	(i)	Union Dawn	Napierville	18.64367	0.03948	0.6524	0.7176
34	(i)	Union Dawn	Philipsburg	18.99363	0.04029	0.6647	0.7312
35	(i)	Union Dawn	East Hereford	22.70383	0.04889	0.7953	0.8748
36	(i)	Union Dawn	Welwyn	41.73330	0.09300	1.4651	1.6116
37		Enbridge CDA	Empress	59.63212	0.13449	2.0950	2.3045
38		Enbridge CDA	Transgas SSDA	50.91651	0.11520	1.7892	1.9681
39		Enbridge CDA	Centram SSDA	47.37427	0.10608	1.6636	1.8300
40		Enbridge CDA	Centram MDA	41.98183	0.09419	1.4744	1.6218
41		Enbridge CDA	Centrat MDA	40.25370	0.08955	1.4130	1.5543
42		Enbridge CDA	Union WDA	31.07610	0.06816	1.0899	1.1989
43		Enbridge CDA	Nipigon WDA	27.28392	0.05947	0.9565	1.0522
44		Enbridge CDA	Union NDA	12.21780	0.02521	0.4269	0.4696
45		Enbridge CDA	Calstock NDA	20.65481	0.04410	0.7232	0.7955
46		Enbridge CDA	Tunis NDA	15.43555	0.03200	0.5395	0.5935
47		Enbridge CDA	GMIT NDA	11.60428	0.02294	0.4044	0.4448
48		Enbridge CDA	Union SSMDA	19.68772	0.04187	0.6892	0.7581
49		Enbridge CDA	Union NCDA	5.20928	0.00836	0.1797	0.1977
50		Enbridge CDA	Union CDA	3.45710	0.00387	0.1176	0.1294
51		Enbridge CDA	Enbridge CDA	1.61112	0.00000	0.0530	0.0583
52		Enbridge CDA	Union EDA	7.63512	0.01407	0.2651	0.2916
53		Enbridge CDA	Enbridge EDA	10.44758	0.02045	0.3640	0.4004
54		Enbridge CDA	GMIT EDA	13.74250	0.02816	0.4800	0.5280
55		Enbridge CDA	KPUC EDA	7.18033	0.01283	0.2489	0.2738
56		Enbridge CDA	North Bay Junction	8.73008	0.01646	0.3035	0.3339
57		Enbridge CDA	Enbridge SWDA	7.49100	0.01360	0.2599	0.2859
58		Enbridge CDA	Union SWDA	7.69845	0.01385	0.2670	0.2937
59		Enbridge CDA	Spruce	40.25370	0.08955	1.4130	1.5543
60		Enbridge CDA	Emerson 1	39.36098	0.08747	1.3816	1.5198
61		Enbridge CDA	Emerson 2	39.36098	0.08747	1.3816	1.5198
62		Enbridge CDA	St. Clair	7.97064	0.01471	0.2767	0.3044
63		Enbridge CDA	Dawn Export	7.49321	0.01360	0.2600	0.2860
64		Enbridge CDA	Kirkwall	3.71165	0.00484	0.1268	0.1395
65		Enbridge CDA	Niagara Falls	5.05535	0.00803	0.1742	0.1916
66		Enbridge CDA	Chippawa	5.11849	0.00817	0.1765	0.1942
67		Enbridge CDA	Iroquois	9.64565	0.01855	0.3357	0.3693
68		Enbridge CDA	Cornwall	10.49469	0.02052	0.3655	0.4021
69		Enbridge CDA	Napierville	13.57413	0.02766	0.4740	0.5214
70		Enbridge CDA	Philipsburg	13.92409	0.02847	0.4863	0.5349
71		Enbridge CDA	East Hereford	17.63429	0.03707	0.6169	0.6786
72		Enbridge CDA	Welwyn	47.37427	0.10608	1.6636	1.8300
73		Enbridge EDA	Empress	61.58233	0.13902	2.1636	2.3800
74		Enbridge EDA	Transgas SSDA	52.86873	0.11974	1.8579	2.0437
75		Enbridge EDA	Centram SSDA	49.32448	0.11061	1.7322	1.9054
76		Enbridge EDA	Centram MDA	43.96591	0.09881	1.5443	1.6987
77		Enbridge EDA	Centrat MDA	41.50601	0.09248	1.4571	1.6028
78		Enbridge EDA	Union WDA	32.19772	0.07081	1.1294	1.2423

Revised Schedule 5B

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2011 through October 2012		
Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (3,186,356)	Page 2
NH Division Storage Contract Capacity Assignment	$ (248,676)	Page 3
NH Division Peaking Demand	$ (311,869)	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	$ (3,574,514)	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)	$ (198,313)
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	$ 1,351,367	$ -	$ -	Y	4,605	-	(379)	-	$ (111,220)
Tennessee	5083	$ 2,225,558	$ -	$ -	Y	8,550	-	(703)	-	$ (182,990)
Tennessee	5265	$ -	$ 270,275	$ -	Y	-	2,653	-	(217)	$ (22,107)
Tennessee	5292	$ 125,521	$ -	$ -	Y	1,406	-	(116)	-	$ (10,356)
Tennessee	46314	$ 35,338	$ -	$ -	Y	950	-	(78)	-	$ (2,901)
Tennessee	31861	$ 198,727	$ -	$ -	Y	2,226	-	(183)	-	$ (16,337)
Tennessee	39735	$ 82,937	$ -	$ -	Y	929	-	(76)	-	$ (6,785)
Tennessee	41099	$ 380,937	$ -	$ -	Y	4,267	-	(351)	-	$ (31,336)
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	$ -	$ 2,046,610	$ -	Y	-	34,000	-	(2,787)	$ (167,762)
TransCanada	33322	$ -	$ 12,042,698	$ -	Y	-	34,000	-	(2,787)	$ (987,147)
TransCanada	29594	$ 146,459	$ -	$ -	Y	5,937	-	(488)	-	$ (12,038)
TransCanada	29594	$ 805,105	$ -	$ -	Y	5,937	-	(488)	-	$ (66,177)
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 $ (3,186,356)

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	$ 144,075	Y	N	(21,256)	(348)	$ (11,809)
W-10	01052	$ 2,890,000	Y	Y	(278,668)	(2,787)	$ (236,868)

Total NH Division Storage Capacity Assignment $ (248,676)

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	$ 10.15	$ (51,978)
Dec-11	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Jan-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Feb-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Mar-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Apr-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)

Total Division Peaking Demand Revenue $ (311,869)

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.
NH Division Peaking Capacity Assignment Demand Rate
November 2011 through April 2012

Line	Description	Northern	NH Division
1	Capacity Allocation Factor		47.38%
2	Peaking Contracts	31,888	15,109
3	Peaking Plants	10,000	4,738
4	Total	41,888	19,847
5	Peaking Contracts Costs	$ 508,750	$ 241,046
6	Peaking Allocated Pipeline Demand Costs	$ 1,303,860	$ 617,769
7	Peaking Plants		$ 349,700
8	Capacity Costs (Before Cap Assignment)		$ 1,208,515
9	NH Division Peaking Capacity Assignment Rate		$ 10.15

New Page

Revised Schedule 6A

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	$ 265,278	$ -	$ 90,870	$ 17,983	$ 44,882	$ 387,726	$ 806,740
Lewiston Baseload	$ 904,365	$ 984,808	$ 1,013,793	$ 951,896	$ 1,011,747	$ 327,075	$ 5,193,684
PNGTS	$ 163,344	$ 177,934	$ 183,204	$ 172,022	$ 182,832	$ 130,344	$ 1,009,678
Niagara	$ -	$ -	$ 24,301	$ -	$ 1,741	$ 25,551	$ 51,593
Tennessee Production	$ 1,183,227	$ 1,334,370	$ 584,788	$ 371,524	$ 1,379,322	$ 1,525,090	$ 6,378,322
Tenn Zone 4 Spot	$ 216,973	$ 216,862	$ -	$ -	$ 288	$ 267,634	$ 701,757
W10 AMA Spot	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Pipeline	$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 14,141,773
Underground Storage							
Tennessee Storage	$ -	$ 57,010	$ 298,015	$ 278,789	$ 295,958	$ -	$ 929,771
Washington 10 Storage	$ 381,888	$ 2,032,735	$ 3,430,195	$ 3,141,601	$ 1,509,844	$ -	$ 10,496,263
Subtotal Storage	$ 381,888	$ 2,089,745	$ 3,728,210	$ 3,420,390	$ 1,805,801	$ -	$ 11,426,035
Peaking Supplies							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 79,291
Subtotal Peaking	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 79,291
Total Commodity Cost	$ 3,123,701	$ 4,812,673	$ 5,648,565	$ 4,942,871	$ 4,436,092	$ 2,683,196	$ 25,647,099

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	$ 4.033		$ 4.532	$ 4.558	$ 4.519	$ 4.346	$ 4.270
Lewiston Baseload	$ 5.481	$ 5.776	$ 5.946	$ 5.968	$ 5.934	$ 4.361	$ 5.701
PNGTS	$ 5.464	$ 5.760	$ 5.931	$ 5.953	$ 5.919	$ 4.360	$ 5.567
Niagara			$ 4.769		$ 4.752	$ 4.457	$ 4.609
Tennessee Production	$ 3.923	$ 4.230	$ 4.409	$ 4.433	$ 4.394	$ 4.381	$ 4.265
Tenn Zone 4 Spot	$ 3.914	$ 4.213			$ 4.374	$ 4.360	$ 4.169
W10 AMA Spot							
Subtotal Pipeline	$ 4.425	$ 4.775	$ 5.282	$ 5.480	$ 4.986	$ 4.371	$ 4.783
Underground Storage							
Tennessee Storage		$ 4.683	$ 4.682	$ 4.683	$ 4.682		$ 4.683
Washington 10 Storage	$ 4.515	$ 4.515	$ 4.515	$ 4.515	$ 4.515		$ 4.515
Subtotal Storage	$ 4.515	$ 4.520	$ 4.528	$ 4.529	$ 4.542		$ 4.529
Peaking Supplies							
Peaking Supply 1							
Peaking Supply 2							
Peaking Supply 3							
LNG	$ 6.390	$ 6.419	$ 6.777	$ 6.939	$ 6.795	$ 6.339	$ 6.598
Subtotal Peaking	$ 6.390	$ 6.419	$ 6.777	$ 6.939	$ 6.795	$ 6.339	$ 6.598
Total Cost per Dth	$ 4.439	$ 4.663	$ 4.763	$ 4.786	$ 4.798	$ 4.381	$ 4.670

Revised Schedule 6B

NYMEX Price Forecast

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	$ 258,627	$ -	$ 88,834	$ 17,582	$ 43,874	$ 378,676	$ 787,593
4	Variable Transportation Costs	Sum Lines 26, 46, 56, 66, 76, 86, 96 and 106	$ 6,651	$ -	$ 2,037	$ 401	$ 1,009	$ 9,049	$ 19,147
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 265,278	$ -	$ 90,870	$ 17,983	$ 44,882	$ 387,726	$ 806,740
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.033		$ 4.532	$ 4.558	$ 4.519	$ 4.346	$ 4.270
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.832
11	NYMEX Cost	Line 9 times Line 10	$ 244,213	$ -	$ 84,429	$ 16,715	$ 41,692	$ 372,777	$ 759,825
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	$ 3.750		$ 4.215	$ 4.237	$ 4.203	$ 4.044	$ 3.972
15	Total Purchase Cost	Line 11 plus Line 13	$ 258,627	$ -	$ 88,834	$ 17,582	$ 43,874	$ 378,676	$ 787,593
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	$ 0.0811		$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811
66	Variable Transportation Costs	Line 64 times Line 65	$ 2,312	$ -	$ 522	$ 87	$ 261	$ 2,321	$ 5,503
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	$ 0.0811		$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811
76	Variable Transportation Costs	Line 74 times Line 75	$ 1,167	$ -	$ 319	$ 53	$ 159	$ 1,347	$ 3,045
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	$ 0.0811		$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811	$ 0.0811
96	Variable Transportation Costs	Line 94 times Line 95	$ 1,873	$ -	$ 795	$ 182	$ 390	$ 3,598	$ 6,837
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	$ 904,365	$ 984,808	$ 1,013,793	$ 951,896	$ 1,011,747	$ 327,075	$ 5,193,684
4	Variable Transportation Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 904,365	$ 984,808	$ 1,013,793	$ 951,896	$ 1,011,747	$ 327,075	$ 5,193,684
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.481	$ 5.776	$ 5.946	$ 5.968	$ 5.934	$ 4.361	$ 5.701
7									
8	Portland Supply Costs								
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.890
11	NYMEX Cost	Line 9 times Line 10	$ 584,265	$ 654,038	$ 683,023	$ 642,466	$ 680,977	$ 298,575	$ 3,543,344
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	$ 5.481	$ 5.776	$ 5.946	$ 5.968	$ 5.934	$ 4.361	$ 5.701
15	Total Purchase Cost	Line 11 plus Line 13	$ 904,365	$ 984,808	$ 1,013,793	$ 951,896	$ 1,011,747	$ 327,075	$ 5,193,684

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	$ 163,230	$ 177,816	$ 183,086	$ 171,912	$ 182,714	$ 130,230	$ 1,008,988
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	$ 163,344	$ 177,934	$ 183,204	$ 172,022	$ 182,832	$ 130,344	$ 1,009,678
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.464	$ 5.760	$ 5.931	$ 5.953	$ 5.919	$ 4.360	$ 5.567
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.898
11	NYMEX Cost	Line 9 times Line 10	$ 106,230	$ 118,916	$ 124,186	$ 116,812	$ 123,814	$ 119,430	$ 709,388
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	$ 5.441	$ 5.736	$ 5.906	$ 5.928	$ 5.894	$ 4.341	$ 5.544
15	Total Purchase Cost	Line 11 plus Line 13	$ 163,230	$ 177,816	$ 183,086	$ 171,912	$ 182,714	$ 130,230	$ 1,008,988
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	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	$ 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	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	$ 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	$ -	$ -	$ 23,885	$ -	$ 1,711	$ 25,083	$ 50,678
4	Variable Transportation Costs	Sum Lines 26, 56, 36 and 46	$ -	$ -	$ 416	$ -	$ 30	$ 468	$ 914
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ 24,301	$ -	$ 1,741	$ 25,551	$ 51,593
6	Average Delivered Price	Line 5 divided by Line 2			$ 4.769		$ 4.752	$ 4.457	$ 4.609
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.993
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ 20,590	$ -	$ 1,474	$ 23,018	$ 45,083
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			$ 4.647		$ 4.635	$ 4.338	$ 4.488
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ 23,885	$ -	$ 1,711	$ 25,083	$ 50,678
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			$ 0.0811		$ 0.0811	$ 0.0811	$ 0.0811
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ 177	$ -	$ 30	$ 347	$ 554
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			$ 0.0811			$ 0.0811	$ 0.0811
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ 117	$ -	$ -	$ 118	$ 235
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			$ 0.0811				$ 0.0811
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ 120	$ -	$ -	$ -	$ 120

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 5	106,870	110,433	70,669	45,958	110,433	126,350	570,714
2	City Gate Volumes - Z1	Line 2 of Page 6	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 5	$ 420,100	$ 468,125	$ 312,114	$ 204,031	$ 486,348	$ 554,733	$ 2,445,451
5	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 763,128	$ 866,245	$ 272,674	$ 167,494	$ 892,975	$ 970,357	$ 3,932,871
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 1,183,227	$ 1,334,370	$ 584,788	$ 371,524	$ 1,379,322	$ 1,525,090	$ 6,378,322
7	Average Delivered Price	Line 6 divided by Line 3	$ 3.923	$ 4.230	$ 4.409	$ 4.433	$ 4.394	$ 4.381	$ 4.265

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	$ 3.462	$ 3.757	$ 3.927	$ 3.949	$ 3.915	$ 3.902	$ 3.801
4	Total Purchase Cost	Line 2 times Line 3	$ 386,393	$ 433,295	$ 289,825	$ 189,536	$ 451,517	$ 514,882	$ 2,265,450
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 33,707	$ 34,830	$ 22,289	$ 14,495	$ 34,830	$ 39,851	$ 180,002
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 420,100	$ 468,125	$ 312,114	$ 204,031	$ 486,348	$ 554,733	$ 2,445,451
7	Average Delivered Price	Line 6 divided by Line 2	$ 3.931	$ 4.239	$ 4.417	$ 4.440	$ 4.404	$ 4.390	$ 4.285
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	$ 3.462	$ 3.757	$ 3.927	$ 3.949	$ 3.915	$ 3.902	$ 3.801
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.880
21	NYMEX Cost	Line 25 times Line 26	$ 395,210	$ 442,406	$ 295,656	$ 193,328	$ 460,628	$ 525,307	$ 2,312,535
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	$ 3.462	$ 3.757	$ 3.927	$ 3.949	$ 3.915	$ 3.902	$ 3.801
25	Total Purchase Cost	Line 27 plus Line 29	$ 386,393	$ 433,295	$ 289,825	$ 189,536	$ 451,517	$ 514,882	$ 2,265,450
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	$ 0.3124	$ 0.3124	$ 0.3124	$ 0.3124	$ 0.3124	$ 0.3124	$ 0.3124
36	Variable Transportation Costs	Line 34 times Line 35	$ 33,504	$ 34,620	$ 22,155	$ 14,408	$ 34,620	$ 39,610	$ 178,917
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	$ 3.507	$ 3.802	$ 3.972	$ 3.994	$ 3.960	$ 3.947	$ 3.829
4	Total Purchase Cost	Line 2 times Line 3	$ 709,539	$ 809,827	$ 255,627	$ 157,077	$ 836,991	$ 909,334	$ 3,678,395
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 53,589	$ 56,418	$ 17,046	$ 10,417	$ 55,983	$ 61,023	$ 254,476
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 763,128	$ 866,245	$ 272,674	$ 167,494	$ 892,975	$ 970,357	$ 3,932,871
7	Average Delivered Price	Line 6 divided by Line 2	$ 3.918	$ 4.225	$ 4.401	$ 4.424	$ 4.389	$ 4.375	$ 4.252
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	$ 3.507	$ 3.802	$ 3.972	$ 3.994	$ 3.960	$ 3.947	$ 3.829
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.863
21	NYMEX Cost	Line 25 times Line 26	$ 716,418	$ 817,069	$ 257,815	$ 158,414	$ 844,177	$ 917,167	$ 3,711,061
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	$ 3.507	$ 3.802	$ 3.972	$ 3.994	$ 3.960	$ 3.947	$ 3.829
25	Total Purchase Cost	Line 27 plus Line 29	$ 709,539	$ 809,827	$ 255,627	$ 157,077	$ 836,991	$ 909,334	$ 3,678,395
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	$ 0.2723	$ 0.2723	$ 0.2723	$ 0.2723	$ 0.2723	$ 0.2723	$ 0.2723
36	Variable Transportation Costs	Line 34 times Line 35	$ 53,219	$ 56,028	$ 16,929	$ 10,345	$ 55,597	$ 60,601	$ 252,718
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							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 33 of Page 2							
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	$ -	$ 55,676	$ 291,041	$ 272,264	$ 289,032	$ -	$ 908,013
4	Variable Transportation Costs	Sum Lines 28 and 38	$ -	$ 1,334	$ 6,974	$ 6,524	$ 6,926	$ -	$ 21,759
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ 57,010	$ 298,015	$ 278,789	$ 295,958	$ -	$ 929,771
6	Average Delivered Price	Line 5 divided by Line 2		$ 4.683	$ 4.682	$ 4.683	$ 4.682		$ 4.683
7									
8	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
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		$ 0.0087	$ 0.0087	$ 0.0087	$ 0.0087		$ 0.0087
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ 107	$ 562	$ 525	$ 558	$ -	$ 1,752
12	Inventory Rate	Sch 14, Page 1		$ 4.4998	$ 4.4998	$ 4.4998	$ 4.4998		$ 4.4998
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ 55,568	$ 290,480	$ 271,739	$ 288,474	$ -	$ 906,261
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	$ -	$ 55,676	$ 291,041	$ 272,264	$ 289,032	$ -	$ 908,013
18									
19	Transportation Fuel Losses and Variable Charges								
20	Transportation Segment 2								
21	Tennessee Gas Pipeline (Contract 5265)								
22	Receipt Point: Tennessee FS-MA Withdrawal Meter								
23	Delivery Point: Pleasant St. (Interconnection with Granite)								
24	Received Volume	Line 16	-	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		$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073		$ 0.1073
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ 1,311	$ 6,853	$ 6,411	$ 6,806	$ -	$ 21,381
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	$ 210,899	$ 211,222	$ -	$ -	$ 281	$ 260,908	$ 683,309
4	Variable Transportation Costs	Sum Lines 26, 0, 36 and 0	$ 6,074	$ 5,640	$ -	$ -	$ 7	$ 6,726	$ 18,447
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 216,973	$ 216,862	$ -	$ -	$ 288	$ 267,634	$ 701,757
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.914	$ 4.213			$ 4.374	$ 4.360	$ 4.169
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.792
11	NYMEX Cost	Line 9 times Line 10	$ 199,091	$ 200,259	$ -	$ -	$ 267	$ 247,835	$ 647,452
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	$ 3.751	$ 4.046			$ 4.204	$ 4.191	$ 4.002
15	Total Purchase Cost	Line 11 plus Line 13	$ 210,899	$ 211,222	$ -	$ -	$ 281	$ 260,908	$ 683,309
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
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	$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073	$ 0.1073
26	Variable Transportation Costs	Line 24 times Line 25	$ 5,969	$ 5,542	$ -	$ -	$ 7	$ 6,609	$ 18,127
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	$ 378,526	$ 2,014,840	$ 3,399,998	$ 3,113,945	$ 1,496,552	$ -	$ 10,403,861
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	$ 381,888	$ 2,032,735	$ 3,430,195	$ 3,141,601	$ 1,509,844	$ -	$ 10,496,263
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.515	$ 4.515	$ 4.515	$ 4.515	$ 4.515		$ 4.515
7									
8	Washington 10 Withdrawn Inventory (Segment 1)								
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	$ 4.3780	$ 4.3780	$ 4.3780	$ 4.3780	$ 4.3780		$ 4.3780
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 378,526	$ 2,014,840	$ 3,399,998	$ 3,113,945	$ 1,496,552	$ -	$ 10,403,861
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	$ 378,526	$ 2,014,840	$ 3,399,998	$ 3,113,945	$ 1,496,552	$ -	$ 10,403,861
18									
19	Transportation Fuel Losses and Variable Charges								
20	Transportation Segment 2A								
21	Vector Pipeline (Contract CRL-NUI-0725)								
22	Receipt Point: Washington 10 Withdrawal Meter								
23	Delivery Point: Dawn (Interconnects with TransCanada)								
24	Received Volume	Line 16	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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 13 of Page							
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	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	$ 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	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	$ 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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	
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	Peaking Supply 2 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	
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	Transportation Fuel Losses and Variable Charges								
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	
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	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 79,291
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 79,291
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.390	$ 6.419	$ 6.777	$ 6.939	$ 6.795	$ 6.339	$ 6.598
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	FXW-8	$ 6.3898	$ 6.4186	$ 6.7772	$ 6.9390	$ 6.7947	$ 6.3391	$ 6.5979
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 79,291
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	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 79,291

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	$	3.969	$	5.629	$	7.190	$	7.032	$	4.901	$	4.376	$	5.406
4	Total Purchase Cost	Line 10 times Line 12	$	5,358	$	7,852	$	17,844	$	9,177	$	6,837	$	17,901	$	64,970
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	$	6,695	$	9,234	$	20,301	$	10,469	$	8,218	$	21,951	$	76,867
7	Average Delivered Price	Line 15 divided by Line 11	$	4.959	$	6.619	$	8.180	$	8.022	$	5.891	$	5.366	$	6.396
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	$	3.541	$	3.836	$	4.006	$	4.028	$	3.994	$	3.981	$	3.927
12	Peaking Supply 1 Costs	Line 9 times Line 10	$	4,780	$	5,351	$	9,942	$	5,257	$	5,572	$	16,285	$	47,187
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	$	3.969	$	5.629	$	7.190	$	7.032	$	4.901	$	4.376	$	5.406
16	Total Purchase Cost	Line 14 times (1 - Line 15)	$	5,358	$	7,852	$	17,844	$	9,177	$	6,837	$	17,901	$	64,970
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

Revised Schedule 7

Hedging Gains and Losses

Northern Utilities, Inc.
Hedging Gains and Losses
November 2011 through April 2012
As of 10/10/2011

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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981	$ 3.934
Hedging (Gains) and Losses	$ 133,160	$ 246,840	$ 300,340	$ 305,840	$ 241,420	$ 108,940	$ 1,336,540

Revised Schedule 8

Typical Bill

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								
	COG 1	$1.0837	$118.12						$118.12								
	COG 2	$1.0837		$162.56					$162.56								
	COG 3	$1.0837			$202.65				$202.65								
	COG 4	$1.0837				$203.74			$203.74								
	COG 5	$1.0837					$179.89		$179.89								
	COG 6	$1.0837						$143.05	$143.05								
	LDAC	$0.0426	$4.64	$6.39	$7.97	$8.01	$7.07	$5.62	$39.70								
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	
	COG 1	$0.6673								$60.06						$60.06	
	COG 2	$0.6673									$36.70					$36.70	
	COG 3	$0.5992										$17.98				$17.98	
	COG 4	$0.6685											$20.06			$20.06	
	COG 5	$0.5570												$23.39		$23.39	
	COG 6	$0.5570													$39.55	$39.55	
Summer Period 2011 Avg. COG		$0.6194															
	LDAC	$ 0.0456								$4.10	$2.51	$1.37	$1.37	$1.92	$3.24	$14.50	
		TOTAL	$173.61	$233.25	$287.07	$288.52	$256.52	$207.07	$1,446.05	$106.13	$70.71	$41.15	$44.11	$53.27	$81.15	$396.53	$1,842.57

			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								
	COG 1	$1.0987	$119.76						$119.76								
	COG 2	$1.0736		$161.04					$161.04								
	COG 3	$1.1199			$209.42				$209.42								
	COG 4	$1.1615				$218.36			$218.36								
	COG 5	$1.1615					$192.81		$192.81								
	COG 6	$1.1615						$153.32	$153.32								
Winter Period 2010-2011 Avg. COG		$1.1295															
	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	
	COG 1	$0.6545								$58.91						$58.91	
	COG 2	$0.5969									$32.83					$32.83	
	COG 3	$0.7280										$21.84				$21.84	
	COG 4	$0.7280											$21.84			$21.84	
	COG 5	$0.7280												$30.58		$30.58	
	COG 6	$0.7280													$51.69	$51.69	
Summer Period 2010 Avg. COG		$0.6939															
	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		$1.23	$5.46	($1.85)	($9.68)	($8.55)	($6.80)	($20.19)	$2.58	$4.75	($3.39)	($0.43)	($5.28)	($8.93)	**($10.70)**	($30.89)
	% Chg		0.71%	2.40%	-0.64%	-3.25%	-3.23%	-3.18%	-1.38%	2.49%	7.20%	-7.60%	-0.96%	-9.02%	-9.91%	**-2.63%**	-1.65%

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								
	COG 1	$1.1166	$215.50						$215.50								
	COG 2	$1.1166		$300.37					$300.37								
	COG 3	$1.1166			$332.75				$332.75								
	COG 4	$1.1166				$292.55			$292.55								
	COG 5	$1.1166					$261.28		$261.28								
	COG 6	$1.1166						$190.94	$190.94								
	LDAC	$0.0190	$3.67	$5.11	$5.66	$4.98	$4.45	$3.25	$27.11								
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	
	COG 1	$0.7234								$84.64						$84.64	
	COG 2	$0.7234									$58.60					$58.60	
	COG 3	$0.6553										$47.18				$47.18	
	COG 4	$0.7246											$52.17			$52.17	
	COG 5	$0.6131												$54.57		$54.57	
	COG 6	$0.6131													$87.06	$87.06	
Summer Period 2011 Avg. COG		$0.6755															
	LDAC	$ 0.0166								$1.94	$1.34	$1.20	$1.20	$1.48	$2.36	$9.51	
	TOTAL		$290.29	$394.07	$433.67	$384.51	$346.28	$260.24	$2,109.06	$136.79	$102.92	$89.23	$96.33	$103.24	$148.80	$677.31	$2,786.37

			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								
	COG 1	$1.0980	$211.91						$211.91								
	COG 2	$1.1058		$297.46					$297.46								
	COG 3	$1.1443			$341.00				$341.00								
	COG 4	$1.1859				$310.71			$310.71								
	COG 5	$1.1859					$277.50		$277.50								
	COG 6	$1.1859						$202.79	$202.79								
Winter Period 2010-2011 Avg. COG		$1.1510															
	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	
	COG 1	$0.6905								$80.79						$80.79	
	COG 2	$0.6329									$51.26					$51.26	
	COG 3	$0.7640										$55.01				$55.01	
	COG 4	$0.7640											$55.01			$55.01	
	COG 5	$0.7640												$68.00		$68.00	
	COG 6	$0.7640													$108.49	$108.49	
Summer Period 2010 Avg. COG		$0.7299															
	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		$8.11	$9.20	($1.28)	($12.03)	($10.74)	($7.85)	($14.59)	$2.32	$6.27	($8.77)	($1.67)	($11.99)	($19.13)	**($32.97)**	($47.56)
	% Chg		2.87%	2.39%	-0.29%	-3.03%	-3.01%	-2.93%	-0.69%	1.72%	6.49%	-8.95%	-1.70%	-10.40%	-11.39%	**-4.64%**	-1.68%

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								
	COG 1	$1.1166	$1,734.08						$1,734.08								
	COG 2	$1.1166		$2,878.59					$2,878.59								
	COG 3	$1.1166			$3,645.70				$3,645.70								
	COG 4	$1.1166				$4,581.41			$4,581.41								
	COG 5	$1.1166					$3,798.67		$3,798.67								
	COG 6	$1.1166						$2,761.35	$2,761.35								
	LDAC	$0.0190	$29.51	$48.98	$62.04	$77.96	$64.64	$46.99	$330.11								
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	
	COG 1	$0.7234								$910.04						$910.04	
	COG 2	$0.7234									$507.10					$507.10	
	COG 3	$0.6553										$271.29				$271.29	
	COG 4	$0.7246											$154.34			$154.34	
	COG 5	$0.6131												$223.17		$223.17	
	COG 6	$0.6131													$428.56	$428.56	
Summer Period 2011 Avg. COG		$0.6755															
	LDAC	$ 0.0166								$20.88	$11.64	$6.87	$3.54	$6.04	$11.60	$60.57	
	TOTAL		$2,170.98	$3,564.06	$4,497.76	$5,636.69	$4,683.96	$3,421.35	$23,974.80	$1,132.62	$657.83	$385.00	$248.36	$341.09	$599.51	$3,364.41	$27,339.21

			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								
	COG 1	$1.0980	$1,705.19						$1,705.19								
	COG 2	$1.1058		$2,850.75					$2,850.75								
	COG 3	$1.1443			$3,736.14				$3,736.14								
	COG 4	$1.1859				$4,865.75			$4,865.75								
	COG 5	$1.1859					$4,034.43		$4,034.43								
	COG 6	$1.1859						$2,932.73	$2,932.73								
Winter Period 2010-2011 Avg. COG		$1.1510															
	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	
	COG 1	$0.6905								$868.65						$868.65	
	COG 2	$0.6329									$443.66					$443.66	
	COG 3	$0.7640										$316.30				$316.30	
	COG 4	$0.7640											$162.73			$162.73	
	COG 5	$0.7640												$278.10		$278.10	
	COG 6	$0.7640													$534.04	$534.04	
Summer Period 2010 Avg. COG		$0.7299															
	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		$65.23	$88.17	($14.04)	($188.33)	($156.15)	($113.51)	($318.64)	$24.91	$54.26	($50.43)	($4.94)	($49.03)	($94.16)	**($119.39)**	($438.02)
	% Chg		3.10%	2.54%	-0.31%	-3.23%	-3.23%	-3.21%	-1.31%	2.25%	8.99%	-11.58%	-1.95%	-12.57%	-13.57%	**-3.43%**	-1.58%

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								
	COG 1	$0.9232	$1,589.75						$1,589.75								
	COG 2	$0.9232		$1,925.80					$1,925.80								
	COG 3	$0.9232			$2,151.06				$2,151.06								
	COG 4	$0.9232				$2,153.83			$2,153.83								
	COG 5	$0.9232					$2,115.05		$2,115.05								
	COG 6	$0.9232						$1,728.23	$1,728.23								
	LDAC	$0.0190	$32.72	$39.63	$44.27	$44.33	$43.53	$35.57	$240.05								
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	
	COG 1	$0.5975								$902.23						$902.23	
	COG 2	$0.5975									$820.97					$820.97	
	COG 3	$0.5294										$660.16				$660.16	
	COG 4	$0.5987											$712.45			$712.45	
	COG 5	$0.4872												$589.51		$589.51	
	COG 6	$0.4872													$645.05	$645.05	
Summer Period 2011 Avg. COG		$0.5496															
	LDAC	$ 0.0166								$25.07	$22.81	$20.70	$19.75	$20.09	$21.98	$130.39	
		TOTAL	$2,037.19	$2,444.22	$2,717.06	$2,720.41	$2,673.45	$2,204.92	$14,797.24	$1,138.57	$1,044.45	$871.63	$953.39	$832.93	$902.60	$5,743.57	$20,540.80

			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								
	COG 1	$0.9702	$1,670.68						$1,670.68								
	COG 2	$0.9451		$1,971.48					$1,971.48								
	COG 3	$0.9914			$2,309.96				$2,309.96								
	COG 4	$1.0330				$2,409.99			$2,409.99								
	COG 5	$1.0330					$2,366.60		$2,366.60								
	COG 6	$1.0330						$1,933.78	$1,933.78								
Winter Period 2010-2011 Avg. COG		$1.0010															
	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	
	COG 1	$0.6075								$917.33						$917.33	
	COG 2	$0.5499									$755.56					$755.56	
	COG 3	$0.6810										$849.21				$849.21	
	COG 4	$0.6810											$810.39			$810.39	
	COG 5	$0.6810												$824.01		$824.01	
	COG 6	$0.6810													$901.64	$901.64	
Summer Period 2010 Avg. COG		$0.6469															
	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	($40.64)	$3.13	($104.38)	($201.57)	($197.94)	($161.74)	($703.15)	($34.88)	$47.40	($205.38)	($78.66)	($214.90)	($235.14)	**($721.56)**	($1,424.70)
		% Chg	-1.96%	0.13%	-3.70%	-6.90%	-6.89%	-6.83%	-4.54%	-2.97%	4.75%	-19.07%	-7.62%	-20.51%	-20.67%	**-11.16%**	-6.49%

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	$0.0426
CGA	$1.1295	$1.0837

	Usage (Therms)	Winter 2010-2011 Bill Amount	Winter 2011-2012 Bill Amount	Total Bill		Base Rate		COG		LDAC	
	5	$17.43	$17.33	($0.10)	-0.6%	$0.15	0.9%	($0.23)	-1.3%	($0.02)	-0.1%
	10	$25.35	$25.16	($0.19)	-0.8%	$0.29	1.1%	($0.46)	-1.8%	($0.03)	-0.1%
	20	$41.21	$40.82	($0.39)	-0.9%	$0.59	1.4%	($0.91)	-2.2%	($0.06)	-0.1%
	25	$49.13	$48.65	($0.49)	-1.0%	$0.73	1.5%	($1.14)	-2.3%	($0.08)	-0.2%
	30	$57.06	$56.47	($0.58)	-1.0%	$0.88	1.5%	($1.37)	-2.4%	($0.09)	-0.2%
	45	$80.84	$79.96	($0.88)	-1.1%	$1.32	1.6%	($2.06)	-2.5%	($0.14)	-0.2%
Average Monthly	50	$88.76	$87.79	($0.97)	-1.1%	$1.47	1.7%	($2.29)	-2.6%	($0.15)	-0.2%
	75	$125.61	$124.16	($1.46)	-1.2%	$2.20	1.8%	($3.43)	-2.7%	($0.23)	-0.2%
	125	$199.32	$196.89	($2.43)	-1.2%	$3.67	1.8%	($5.72)	-2.9%	($0.38)	-0.2%
	150	$236.17	$233.25	($2.92)	-1.2%	$4.40	1.9%	($6.86)	-2.9%	($0.45)	-0.2%
	200	$309.87	$305.98	($3.89)	-1.3%	$5.87	1.9%	($9.15)	-3.0%	($0.60)	-0.2%

Revised Schedule 9

Variance Analysis

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		$ 16,309,451	0.5700		$ 1,158,683	$ 0.0427
7										
8	Purchased Gas		6,634,727	0.2309		7,429,043	0.2596		$ 794,316	$ 0.0287
9										
10	Storage & Peaking Gas		8,799,329	0.3062		6,062,922	0.2119		$ (2,736,407)	$ (0.0944)
11										
12	Hedging (Gain)/Loss		1,247,662	0.0434		703,414	0.0246		(544,248)	(0.0188)
13			16,681,718							
14										
15	Total Volumes and Cost	$ -	$ 31,832,486	$ 1.1079	$ -	$ 30,504,831	$ 1.0661	$ -	$ (1,327,655)	$ (0.0418)
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		71,698	$ 0.0025		(67,156)	$ (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)		(11,415)	$ (0.0004)		23,813	$ 0.0008
26	Bad Debt Allowance		1,935	$ 0.0001		379,392	$ 0.0133		377,457	$ 0.0132
27	Fuel Inventory Financing		8,312	$ 0.0003		7,131	$ 0.0002		(1,182)	$ (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		507,320	$ 0.0177		(1,336,758)	$ (0.0465)
32	Total Adjusted Cost	-	$33,676,565	$ 1.1720		$31,012,151	$ 1.0837		($2,664,414)	$ (0.0884)

Revised Schedule 10A

Allocation of Demand Costs

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									

LN	PIPELINE BASE DEMAND COSTS	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
25	TOTAL PIPELINE BASE DEMAND COST	$ 71,957	$ 71,957	$ 71,957	$ 71,957	$ 71,957	$ 71,957	$ 431,742	Schedule 1A, LN 69
26	Res Heat	$ 31,959	$ 31,959	$ 31,959	$ 31,959	$ 31,959	$ 31,959	$ 191,755	LN 25 * LN 14
27	Res General	$ 1,173	$ 1,173	$ 1,173	$ 1,173	$ 1,173	$ 1,173	$ 7,041	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 7,103	$ 7,103	$ 7,103	$ 7,103	$ 7,103	$ 7,103	$ 42,619	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 9,107	$ 9,107	$ 9,107	$ 9,107	$ 9,107	$ 9,107	$ 54,641	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 9,498	$ 9,498	$ 9,498	$ 9,498	$ 9,498	$ 9,498	$ 56,990	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 11,319	$ 11,319	$ 11,319	$ 11,319	$ 11,319	$ 11,319	$ 67,913	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 401	$ 401	$ 401	$ 401	$ 401	$ 401	$ 2,407	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,396	$ 1,396	$ 1,396	$ 1,396	$ 1,396	$ 1,396	$ 8,376	LN 25 * LN 21
34									
35	Residential	$ 33,133	$ 33,133	$ 33,133	$ 33,133	$ 33,133	$ 33,133	$ 198,796	LN 26 + LN 27
36	SALES HLF CLASSES	$ 17,003	$ 17,003	$ 17,003	$ 17,003	$ 17,003	$ 17,003	$ 102,016	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 21,822	$ 21,822	$ 21,822	$ 21,822	$ 21,822	$ 21,822	$ 130,929	LN 29 + LN 31 + LN 33
38									

Remaining Capacity Costs

LN		Column A Design Day Demand (MMBtu)	Column B Avg Daily Base Use Load (MMBtu)	Column C Remaining Design Day Demand (MMBtu)	Column D % of Total Remaining Design Day Demand	
39						
40	Res Heat	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									
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 164,772	$ 346,909	$ 626,061	$ 362,439	$ 270,554	$ 126,503	$ 1,897,237	Schedule 1A, LN 70
53									
54	Res Heat	$ 81,363	$ 171,301	$ 309,144	$ 178,970	$ 133,598	$ 62,466	$ 936,843	LN 40 Col D * LN 52
55	Res General	$ 1,341	$ 2,823	$ 5,095	$ 2,950	$ 2,202	$ 1,030	$ 15,441	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 3,363	$ 7,081	$ 12,778	$ 7,398	$ 5,522	$ 2,582	$ 38,723	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 36,957	$ 77,808	$ 140,419	$ 81,291	$ 60,682	$ 28,373	$ 425,530	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 4,498	$ 9,471	$ 17,092	$ 9,895	$ 7,386	$ 3,454	$ 51,795	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 32,460	$ 68,341	$ 123,334	$ 71,401	$ 53,299	$ 24,921	$ 373,757	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 160	$ 338	$ 610	$ 353	$ 263	$ 123	$ 1,847	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 4,629	$ 9,746	$ 17,589	$ 10,183	$ 7,601	$ 3,554	$ 53,302	LN 47 Col D * LN 52
62	TOTAL	$ 164,772	$ 346,909	$ 626,061	$ 362,439	$ 270,554	$ 126,503	$ 1,897,237	Sum LN 54 : LN 61
63									
64	Residential	$ 82,704	$ 174,124	$ 314,240	$ 181,919	$ 135,800	$ 63,496	$ 952,283	LN 54 + LN 55
65	SALES HLF CLASSES	$ 8,022	$ 16,889	$ 30,479	$ 17,645	$ 13,172	$ 6,159	$ 92,365	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 74,046	$ 155,895	$ 281,342	$ 162,874	$ 121,583	$ 56,848	$ 852,588	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									
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 1,214,184	$ 2,556,321	$ 4,613,353	$ 2,670,759	$ 1,993,674	$ 932,181	$ 14,377,412	Schedule 1A, LN 73
71									
72	Res Heat	$ 599,556	$ 1,262,294	$ 2,278,042	$ 1,318,803	$ 984,463	$ 460,305	$ 6,903,461	LN 40 Col D * LN 70
73	Res General	$ 9,882	$ 20,805	$ 37,546	$ 21,736	$ 16,226	$ 7,587	$ 113,781	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 24,782	$ 52,176	$ 94,160	$ 54,511	$ 40,692	$ 19,026	$ 285,347	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 272,328	$ 573,355	$ 1,034,725	$ 599,022	$ 447,159	$ 209,078	$ 3,135,667	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 33,147	$ 69,788	$ 125,945	$ 72,912	$ 54,428	$ 25,449	$ 381,669	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 239,195	$ 503,597	$ 908,833	$ 526,141	$ 392,755	$ 183,640	$ 2,754,162	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 1,182	$ 2,489	$ 4,491	$ 2,600	$ 1,941	$ 908	$ 13,611	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 34,112	$ 71,818	$ 129,610	$ 75,034	$ 56,011	$ 26,189	$ 392,774	LN 47 Col D * LN 70
80	TOTAL	$ 1,214,184	$ 2,556,321	$ 4,613,353	$ 2,670,759	$ 1,993,674	$ 932,181	$ 13,980,472	Sum LN 72 : LN 79
81									
82	Residential	$ 609,438	$ 1,283,098	$ 2,315,588	$ 1,340,539	$ 1,000,688	$ 467,891	$ 7,017,242	LN 72 + LN 73
83	SALES HLF CLASSES	$ 59,112	$ 124,452	$ 224,597	$ 130,024	$ 97,060	$ 45,382	$ 680,627	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 545,635	$ 1,148,770	$ 2,073,168	$ 1,200,197	$ 895,926	$ 418,908	$ 6,282,603	LN 75 + LN 77 + LN 79
85									

LN		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
86	**CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**								
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**								
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									

Ln		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	WINTER	
122	**REMAINING RE-ENTRY FEE CREDIT**								
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**								
141		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
142	Res Heat	$ 610,016	$ 1,288,366	$ 2,328,042	$ 1,346,206	$ 1,003,990	$ 467,485	$ 7,044,104	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 10,054	$ 21,235	$ 38,370	$ 22,188	$ 16,548	$ 7,705	$ 116,099	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 25,214	$ 53,253	$ 96,227	$ 55,644	$ 41,499	$ 19,323	$ 291,161	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 277,079	$ 585,197	$ 1,057,435	$ 611,469	$ 456,029	$ 212,339	$ 3,199,549	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 33,726	$ 71,229	$ 128,710	$ 74,427	$ 55,507	$ 25,846	$ 389,445	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 243,368	$ 513,998	$ 928,781	$ 537,074	$ 400,546	$ 186,505	$ 2,810,272	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 1,203	$ 2,540	$ 4,590	$ 2,654	$ 1,979	$ 922	$ 13,888	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 34,707	$ 73,302	$ 132,454	$ 76,593	$ 57,122	$ 26,598	$ 400,776	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 1,235,367	$ 2,609,120	$ 4,714,610	$ 2,726,255	$ 2,033,220	$ 946,721	$ 14,265,294	Sum LN 142 : LN 149
151									
152	Residential	$ 620,070	$ 1,309,600	$ 2,366,412	$ 1,368,394	$ 1,020,537	$ 475,190	$ 7,160,204	LN 142 + LN 143
153	SALES HLF CLASSES	$ 60,143	$ 127,023	$ 229,527	$ 132,725	$ 98,986	$ 46,090	$ 694,494	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 555,155	$ 1,172,497	$ 2,118,671	$ 1,225,136	$ 913,697	$ 425,442	$ 6,410,597	LN 145 + LN 147 + LN 149
155									
156	**TOTAL CAPACITY COSTS**								
157		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**WINTER**	
158	Res Heat	$ 641,975	$ 1,320,325	$ 2,360,001	$ 1,378,165	$ 1,035,949	$ 499,444	$ 7,235,860	LN 142 + LN 26
159	Res General	$ 11,228	$ 22,408	$ 39,544	$ 23,361	$ 17,721	$ 8,878	$ 123,140	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 32,318	$ 60,356	$ 103,330	$ 62,747	$ 48,602	$ 26,426	$ 333,780	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 286,186	$ 594,304	$ 1,066,542	$ 620,576	$ 465,136	$ 221,446	$ 3,254,190	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 43,224	$ 80,728	$ 138,208	$ 83,926	$ 65,006	$ 35,344	$ 446,435	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 254,687	$ 525,317	$ 940,100	$ 548,393	$ 411,864	$ 197,823	$ 2,878,184	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,604	$ 2,941	$ 4,991	$ 3,055	$ 2,381	$ 1,323	$ 16,295	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 36,103	$ 74,698	$ 133,850	$ 77,989	$ 58,518	$ 27,994	$ 409,152	LN 149 + LN 33
166	TOTAL	$ 1,307,324	$ 2,681,077	$ 4,786,567	$ 2,798,212	$ 2,105,177	$ 1,018,678	$ 14,697,036	Sum LN 158 : LN 165
167									
168	Residential	$ 653,203	$ 1,342,733	$ 2,399,545	$ 1,401,527	$ 1,053,670	$ 508,322	$ 7,359,000	LN 158 + LN 159
169	SALES HLF CLASSES	$ 77,146	$ 144,026	$ 246,529	$ 149,728	$ 115,988	$ 63,093	$ 796,510	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 576,976	$ 1,194,319	$ 2,140,493	$ 1,246,957	$ 935,518	$ 447,263	$ 6,541,526	LN 161 + LN 163 + LN 165
171									
172	% ALLOCATION BETWEEN SALES HLF AND LLF								
173	SALES HLF CLASSES							10.85%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES							89.15%	LN 170 / (LN 169 + LN 170)

Revised Schedule 10B

Forecast Firm Sales

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	TOTAL	Winter
1	Res Heat	1,703,736	2,515,331	2,874,218	2,520,436	2,235,457	1,469,786	16,637,146	13,318,964
2	Res General	27,273	40,265	46,010	40,347	35,785	23,528	335,046	213,210
3	**Total Residential**	**1,731,009**	**2,555,596**	**2,920,229**	**2,560,783**	**2,271,243**	**1,493,314**	**16,972,192**	**13,532,174**
4	G50 Low Annual-Low Winter	136,918	202,141	230,982	202,551	179,649	118,117	1,807,855	1,070,359
5	G40 Low Annual-High Winter	814,054	1,201,838	1,373,317	1,204,278	1,068,113	702,271	7,309,393	6,363,871
6	G51 Med Annual-Low Winter	183,076	270,286	308,851	270,835	240,212	157,937	2,417,366	1,431,197
7	G41 Med Annual-High Winter	688,478	1,016,443	1,161,469	1,018,506	903,346	593,939	6,557,356	5,382,181
8	G52 High Annual-Low Winter	7,427	8,655	10,417	10,125	9,124	8,050	91,057	53,799
9	G42 High Annual-High Winter	99,888	147,471	168,512	147,770	131,062	86,172	925,811	780,877
10	**Total C&I**	**1,929,842**	**2,846,834**	**3,253,548**	**2,854,065**	**2,531,508**	**1,666,487**	**19,108,838**	**15,082,284**
11	**Total 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**
12									
13	Residential Heat & Non Heat	1,731,009	2,555,596	2,920,229	2,560,783	2,271,243	1,493,314	16,972,192	13,532,174
14	SALES HLF CLASSES	327,421	481,082	550,250	483,511	428,986	284,104	4,316,278	2,555,355
15	SALES LLF CLASSES	1,602,420	2,365,752	2,703,298	2,370,554	2,102,522	1,382,382	14,792,560	12,526,929
16	**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**
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**	**TOTAL**	**Winter**
21	Res Heat	1,719,950	2,539,150	2,901,403	2,544,320	2,256,696	1,483,893	16,796,533	13,445,412
22	Res General	27,533	40,647	46,446	40,729	36,125	23,754	338,280	215,234
23	G50 Low Annual-Low Winter	138,221	204,055	233,167	204,471	181,356	119,251	1,825,338	1,080,521
24	G40 Low Annual-High Winter	821,801	1,213,219	1,386,306	1,215,689	1,078,261	709,012	7,379,196	6,424,289
25	G51 Med Annual-Low Winter	184,818	272,846	311,772	273,401	242,495	159,453	2,440,742	1,444,785
26	G41 Med Annual-High Winter	695,030	1,026,068	1,172,454	1,028,157	911,929	599,640	6,620,119	5,433,279
27	G52 High Annual-Low Winter	7,498	8,737	10,516	10,221	9,211	8,128	91,939	54,310
28	G42 High Annual-High Winter	100,839	148,868	170,106	149,171	132,308	86,999	934,663	788,290
29	**Subtotal**								
30	Residential	1,747,483	2,579,797	2,947,849	2,585,049	2,292,821	1,507,648	17,134,812	13,660,646
31	SALES HLF CLASSES	330,537	485,638	555,455	488,093	433,061	286,831	4,358,019	2,579,616
32	SALES LLF CLASSES	1,617,670	2,388,155	2,728,866	2,393,018	2,122,498	1,395,651	14,933,979	12,645,858
33	**Total Firm Sales**	3,695,690	5,453,590	6,232,170	5,466,160	4,848,380	3,190,130	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
Res General	567
G50 Low Annual-Low Winter	3,430
G40 Low Annual-High Winter	4,398
G51 Med Annual-Low Winter	4,587
G41 Med Annual-High Winter	5,466
G52 High Annual-Low Winter	194
G42 High Annual-High Winter	674
Subtotal	
Residential	15,999
SALES HLF CLASSES	8,210
SALES LLF CLASSES	10,537
Total Firm Sales	**34,747**

BASE SENDOUT BY CLASS - Therms								
Days per Month	30	31	31	29	31	30		
	Nov-11	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
Res Heat	462,979	478,412	478,412	447,547	478,412	462,979	5,644,196	2,808,740
Res General	17,000	17,566	17,566	16,433	17,566	17,000	207,242	103,131
G50 Low Annual-Low Winter	102,901	106,331	106,331	99,471	106,331	102,901	1,254,473	624,268
G40 Low Annual-High Winter	131,927	136,324	136,324	127,529	136,324	131,927	1,608,324	800,356
G51 Med Annual-Low Winter	137,598	142,185	142,185	133,011	142,185	137,598	1,677,463	834,762
G41 Med Annual-High Winter	163,970	169,435	169,435	158,504	169,435	163,970	1,998,961	994,750
G52 High Annual-Low Winter	5,811	6,005	6,005	5,617	6,005	5,811	70,892	35,254
G42 High Annual-High Winter	20,222	20,896	20,896	19,548	20,896	20,222	246,532	122,682
Subtotal								
Residential	479,979	495,978	495,978	463,979	495,978	479,979	5,851,438	2,911,871
SALES HLF CLASSES	246,311	254,521	254,521	238,100	254,521	246,311	3,002,829	1,494,284
SALES LLF CLASSES	316,119	326,656	326,656	305,582	326,656	316,119	3,853,817	1,917,788
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

REMAINING SENDOUT BY CLASS - Therms								
	Nov-11	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
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
Res General	10,533	23,080	28,879	24,297	18,559	6,755	131,037	112,103
G50 Low Annual-Low Winter	35,320	97,724	126,836	104,999	75,025	16,350	570,865	456,254
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
G51 Med Annual-Low Winter	47,220	130,661	169,587	140,390	100,310	21,855	763,279	610,023
G41 Med Annual-High Winter	531,060	856,633	1,003,019	869,653	742,493	435,670	4,621,158	4,438,529
G52 High Annual-Low Winter	1,687	2,732	4,511	4,603	3,206	2,317	21,046	19,055
G42 High Annual-High Winter	80,616	127,971	149,210	129,623	111,411	66,777	688,132	665,608
Subtotal								
Residential	1,267,504	2,083,819	2,451,871	2,121,070	1,796,843	1,027,669	11,283,374	10,748,776
SALES HLF CLASSES	84,227	231,117	300,934	249,993	178,541	40,521	1,355,190	1,085,332
SALES LLF CLASSES	1,301,551	2,061,499	2,402,210	2,087,436	1,795,841	1,079,532	11,080,162	10,728,070
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

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
Sales Service Deliveries Forecast by Rate Class

Forecast Calendar 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 Calendar 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%

Revised Schedule 10C

Allocation of Commodity Costs

To Firm Sales

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

Base Commodity Costs

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	$ 461,221	$ 514,377	$ 568,916	$ 552,224	$ 537,054	$ 455,629	$ 5,935,926	$ 3,089,421
24	Res Heat	$ 204,849	$ 228,458	$ 252,680	$ 245,267	$ 238,529	$ 202,365	$ 2,636,395	$ 1,372,148
25	Res General	$ 7,522	$ 8,388	$ 9,278	$ 9,006	$ 8,758	$ 7,430	$ 96,803	$ 50,382
26	G50 Low Annual-Low Winter	$ 45,529	$ 50,777	$ 56,160	$ 54,513	$ 53,015	$ 44,977	$ 585,962	$ 304,972
27	G40 Low Annual-High Winter	$ 58,372	$ 65,099	$ 72,002	$ 69,889	$ 67,969	$ 57,664	$ 751,246	$ 390,996
28	G51 Med Annual-Low Winter	$ 60,881	$ 67,898	$ 75,097	$ 72,894	$ 70,891	$ 60,143	$ 783,541	$ 407,804
29	G41 Med Annual-High Winter	$ 72,550	$ 80,911	$ 89,490	$ 86,864	$ 84,478	$ 71,670	$ 933,712	$ 485,963
30	G52 High Annual-Low Winter	$ 2,571	$ 2,868	$ 3,172	$ 3,079	$ 2,994	$ 2,540	$ 33,113	$ 17,223
31	G42 High Annual-High Winter	$ 8,948	$ 9,979	$ 11,037	$ 10,713	$ 10,419	$ 8,839	$ 115,155	$ 59,934
32									
33	Residential	$ 212,370	$ 236,846	$ 261,958	$ 254,273	$ 247,288	$ 209,795	$ 2,733,198	$ 1,422,530
34	SALES HLF CLASSES	$ 108,982	$ 121,542	$ 134,429	$ 130,485	$ 126,900	$ 107,661	$ 1,402,616	$ 729,999
35	SALES LLF CLASSES	$ 139,869	$ 155,989	$ 172,528	$ 167,466	$ 162,866	$ 138,173	$ 1,800,112	$ 936,893

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**							**TOTAL**	**WINTER**
37	TOTAL BASE HEDGING COMMODITY	$ 22,471	$ 46,783	$ 90,075	$ 111,596	$ 49,472	$ 18,636	$ 366,215	$ 339,033
38	Res Heat	$ 9,980	$ 20,779	$ 40,006	$ 49,565	$ 21,972	$ 8,277	$ 162,652	$ 150,579
39	Res General	$ 366	$ 763	$ 1,469	$ 1,820	$ 807	$ 304	$ 5,972	$ 5,529
40	G50 Low Annual-Low Winter	$ 2,218	$ 4,618	$ 8,892	$ 11,016	$ 4,884	$ 1,840	$ 36,151	$ 33,468
41	G40 Low Annual-High Winter	$ 2,844	$ 5,921	$ 11,400	$ 14,124	$ 6,261	$ 2,359	$ 46,348	$ 42,908
42	G51 Med Annual-Low Winter	$ 2,966	$ 6,175	$ 11,890	$ 14,731	$ 6,530	$ 2,460	$ 48,340	$ 44,752
43	G41 Med Annual-High Winter	$ 3,535	$ 7,359	$ 14,169	$ 17,554	$ 7,782	$ 2,931	$ 57,605	$ 53,329
44	G52 High Annual-Low Winter	$ 125	$ 261	$ 502	$ 622	$ 276	$ 104	$ 2,042	$ 1,890
45	G42 High Annual-High Winter	$ 436	$ 908	$ 1,747	$ 2,165	$ 960	$ 362	$ 7,104	$ 6,577
46									
47	Residential	$ 10,347	$ 21,541	$ 41,475	$ 51,385	$ 22,779	$ 8,581	$ 168,624	$ 156,108
48	SALES HLF CLASSES	$ 5,310	$ 11,054	$ 21,284	$ 26,369	$ 11,690	$ 4,404	$ 86,533	$ 80,110
49	SALES LLF CLASSES	$ 6,814	$ 14,187	$ 27,316	$ 33,842	$ 15,003	$ 5,652	$ 111,058	$ 102,814

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	$ 1,180,229	$ 2,030,069	$ 2,401,127	$ 2,065,363	$ 1,790,260	$ 942,627	$ 10,935,223	$ 10,409,675
73	Res Heat	$ 559,124	$ 955,901	$ 1,128,592	$ 971,313	$ 844,180	$ 448,076	$ 5,141,510	$ 4,907,186
74	Res General	$ 4,685	$ 10,706	$ 13,452	$ 11,255	$ 8,810	$ 2,965	$ 60,477	$ 51,873
75	G50 Low Annual-Low Winter	$ 15,711	$ 45,331	$ 59,078	$ 48,640	$ 35,615	$ 7,176	$ 263,632	$ 211,551
76	G40 Low Annual-High Winter	$ 306,869	$ 499,532	$ 582,222	$ 504,081	$ 447,152	$ 253,281	$ 2,659,909	$ 2,593,138
77	G51 Med Annual-Low Winter	$ 21,004	$ 60,609	$ 78,991	$ 65,034	$ 47,619	$ 9,592	$ 352,491	$ 282,850
78	G41 Med Annual-High Winter	$ 236,226	$ 397,361	$ 467,191	$ 402,860	$ 352,473	$ 191,214	$ 2,130,313	$ 2,047,324
79	G52 High Annual-Low Winter	$ 750	$ 1,267	$ 2,101	$ 2,133	$ 1,522	$ 1,017	$ 9,692	$ 8,790
80	G42 High Annual-High Winter	$ 35,860	$ 59,361	$ 69,500	$ 60,047	$ 52,889	$ 29,308	$ 317,199	$ 306,964
81									
82	Residential	$ 563,809	$ 966,608	$ 1,142,044	$ 982,568	$ 852,990	$ 451,040	$ 5,201,987	$ 4,959,059
83	SALES HLF CLASSES	$ 37,466	$ 107,207	$ 140,170	$ 115,807	$ 84,756	$ 17,784	$ 625,815	$ 503,190
84	SALES LLF CLASSES	$ 578,954	$ 956,254	$ 1,118,913	$ 966,988	$ 852,514	$ 473,803	$ 5,107,420	$ 4,947,426

85	**REMAINING COMMODITY HEDGING COSTS**							**TOTAL**	**WINTER**
86	TOTAL REMAINING COMMODITY HEDGING	$ 47,467	$ 83,649	$ 67,759	$ 50,280	$ 77,120	$ 38,107	$ 376,547	$ 364,382
87	Res Heat	$ 22,487	$ 39,388	$ 31,848	$ 23,646	$ 36,365	$ 18,114	$ 177,276	$ 171,849
88	Res General	$ 188	$ 441	$ 380	$ 274	$ 380	$ 120	$ 1,982	$ 1,783
89	G50 Low Annual-Low Winter	$ 632	$ 1,868	$ 1,667	$ 1,184	$ 1,534	$ 290	$ 8,382	$ 7,175
90	G40 Low Annual-High Winter	$ 12,342	$ 20,583	$ 16,430	$ 12,272	$ 19,262	$ 10,239	$ 92,674	$ 91,128
91	G51 Med Annual-Low Winter	$ 845	$ 2,497	$ 2,229	$ 1,583	$ 2,051	$ 388	$ 11,206	$ 9,594
92	G41 Med Annual-High Winter	$ 9,501	$ 16,373	$ 13,184	$ 9,807	$ 15,184	$ 7,730	$ 73,701	$ 71,779
93	G52 High Annual-Low Winter	$ 30	$ 52	$ 59	$ 52	$ 66	$ 41	$ 315	$ 300
94	G42 High Annual-High Winter	$ 1,442	$ 2,446	$ 1,961	$ 1,462	$ 2,278	$ 1,185	$ 11,011	$ 10,774
95								$ -	$ -
96	Residential	$ 22,676	$ 39,829	$ 32,228	$ 23,920	$ 36,745	$ 18,234	$ 179,257	$ 173,631
97	SALES HLF CLASSES	$ 1,507	$ 4,417	$ 3,956	$ 2,819	$ 3,651	$ 719	$ 19,903	$ 17,069
98	SALES LLF CLASSES	$ 23,285	$ 39,403	$ 31,575	$ 23,541	$ 36,724	$ 19,154	$ 177,387	$ 173,681

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

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	$ 1,641,450	$ 2,544,446	$ 2,970,042	$ 2,617,587	$ 2,327,314	$ 1,398,257	$ 16,871,148	$ 13,499,096
101	Res Heat	$ 763,972	$ 1,184,359	$ 1,381,273	$ 1,216,580	$ 1,082,709	$ 650,441	$ 7,777,905	$ 6,279,333
102	Res General	$ 12,207	$ 19,095	$ 22,729	$ 20,261	$ 17,568	$ 10,395	$ 157,280	$ 102,255
103	G50 Low Annual-Low Winter	$ 61,240	$ 96,107	$ 115,239	$ 103,153	$ 88,631	$ 52,153	$ 849,594	$ 516,523
104	G40 Low Annual-High Winter	$ 365,241	$ 564,632	$ 654,224	$ 573,971	$ 515,122	$ 310,945	$ 3,411,154	$ 2,984,134
105	G51 Med Annual-Low Winter	$ 81,886	$ 128,507	$ 154,088	$ 137,928	$ 118,510	$ 69,735	$ 1,136,032	$ 690,654
106	G41 Med Annual-High Winter	$ 308,775	$ 478,272	$ 556,681	$ 489,724	$ 436,951	$ 262,884	$ 3,064,025	$ 2,533,287
107	G52 High Annual-Low Winter	$ 3,322	$ 4,135	$ 5,273	$ 5,211	$ 4,516	$ 3,557	$ 42,805	$ 26,012
108	G42 High Annual-High Winter	$ 44,807	$ 69,340	$ 80,536	$ 70,760	$ 63,307	$ 38,147	$ 432,353	$ 366,898
109									
110	Residential	$ 776,179	$ 1,203,454	$ 1,404,002	$ 1,236,841	$ 1,100,277	$ 660,835	$ 7,935,185	$ 6,381,589
111	SALES HLF CLASSES	$ 146,448	$ 228,749	$ 274,599	$ 246,292	$ 211,657	$ 125,445	$ 2,028,431	$ 1,233,189
112	SALES LLF CLASSES	$ 718,823	$ 1,112,243	$ 1,291,441	$ 1,134,454	$ 1,015,380	$ 611,976	$ 6,907,532	$ 5,884,318
113	**TOTAL HEDGING COMMODITY COSTS**							**TOTAL**	**WINTER**
114	TOTAL HEDGING COMMODITY	$ 69,938	$ 130,433	$ 157,834	$ 161,876	$ 126,592	$ 56,743	$ 742,762	$ 703,414
115	Res Heat	$ 32,467	$ 60,167	$ 71,855	$ 73,211	$ 58,338	$ 26,391	$ 339,928	$ 322,428
116	Res General	$ 555	$ 1,204	$ 1,849	$ 2,094	$ 1,186	$ 424	$ 7,954	$ 7,311
117	G50 Low Annual-Low Winter	$ 2,850	$ 6,486	$ 10,559	$ 12,200	$ 6,418	$ 2,130	$ 44,532	$ 40,643
118	G40 Low Annual-High Winter	$ 15,186	$ 26,504	$ 27,830	$ 26,395	$ 25,523	$ 12,598	$ 139,023	$ 134,036
119	G51 Med Annual-Low Winter	$ 3,811	$ 8,673	$ 14,119	$ 16,314	$ 8,582	$ 2,848	$ 59,547	$ 54,346
120	G41 Med Annual-High Winter	$ 13,035	$ 23,732	$ 27,353	$ 27,361	$ 22,966	$ 10,661	$ 131,306	$ 125,108
121	G52 High Annual-Low Winter	$ 155	$ 313	$ 561	$ 674	$ 341	$ 145	$ 2,356	$ 2,190
122	G42 High Annual-High Winter	$ 1,878	$ 3,354	$ 3,709	$ 3,627	$ 3,238	$ 1,546	$ 18,116	$ 17,351
123									
124	Residential	$ 33,022	$ 61,371	$ 73,703	$ 75,305	$ 59,524	$ 26,815	$ 347,882	$ 329,739
125	SALES HLF CLASSES	$ 6,816	$ 15,472	$ 25,239	$ 29,188	$ 15,341	$ 5,123	$ 106,436	$ 97,179
126	SALES LLF CLASSES	$ 30,099	$ 53,590	$ 58,891	$ 57,383	$ 51,727	$ 24,805	$ 288,445	$ 276,496
127	TOTAL COMMODITY	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**	**WINTER**
128	Res Heat	$ 796,440	$ 1,244,526	$ 1,453,127	$ 1,289,791	$ 1,141,047	$ 676,832	$ 8,117,833	$ 6,601,761
129	Res General	$ 12,762	$ 20,299	$ 24,578	$ 22,355	$ 18,755	$ 10,819	$ 165,234	$ 109,567
130	G50 Low Annual-Low Winter	$ 64,090	$ 102,593	$ 125,798	$ 115,353	$ 95,049	$ 54,283	$ 894,127	$ 557,166
131	G40 Low Annual-High Winter	$ 380,427	$ 591,136	$ 682,054	$ 600,366	$ 540,645	$ 323,543	$ 3,550,177	$ 3,118,169
132	G51 Med Annual-Low Winter	$ 85,697	$ 137,180	$ 168,207	$ 154,242	$ 127,091	$ 72,583	$ 1,195,579	$ 745,000
133	G41 Med Annual-High Winter	$ 321,810	$ 502,004	$ 584,033	$ 517,085	$ 459,917	$ 273,546	$ 3,195,331	$ 2,658,395
134	G52 High Annual-Low Winter	$ 3,477	$ 4,448	$ 5,834	$ 5,885	$ 4,857	$ 3,702	$ 45,161	$ 28,203
135	G42 High Annual-High Winter	$ 46,685	$ 72,694	$ 84,245	$ 74,386	$ 66,545	$ 39,693	$ 450,469	$ 384,249
136	Total Firm Sales	$ 1,711,388	$ 2,674,879	$ 3,127,876	$ 2,779,463	$ 2,453,906	$ 1,454,999	$ 17,613,910	$ 14,202,510
137									
138	Residential	$ 809,202	$ 1,264,824	$ 1,477,705	$ 1,312,145	$ 1,159,801	$ 687,650	$ 8,283,067	$ 6,711,328
139	SALES HLF CLASSES	$ 153,264	$ 244,221	$ 299,839	$ 275,480	$ 226,997	$ 130,568	$ 2,134,867	$ 1,330,369
140	SALES LLF CLASSES	$ 748,922	$ 1,165,833	$ 1,350,332	$ 1,191,837	$ 1,067,107	$ 636,782	$ 7,195,977	$ 6,160,814
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								17.76%
144	SALES LLF CLASSES								82.24%

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)

Revised Schedule 14

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	$ 906,261	$ 4.50	NA	$ -	$ 4.50	$ -	$ 906,261	2.19%	$ 1,651	$ 906,261	$ -
Dec-11	201,401	-	12,349	189,052	$ 906,261	$ 4.50	NA	$ -	$ 4.50	$ 55,568	$ 850,692	2.19%	$ 1,601	$ 850,692	$ 55,568
Jan-12	189,052	-	64,554	124,498	$ 850,692	$ 4.50	NA	$ -	$ 4.50	$ 290,480	$ 560,213	2.19%	$ 1,285	$ 560,213	$ 290,480
Feb-12	124,498	-	60,389	64,108	$ 560,213	$ 4.50	NA	$ -	$ 4.50	$ 271,739	$ 288,474	2.19%	$ 773	$ 288,474	$ 271,739
Mar-12	64,108	-	64,108	-	$ 288,474	$ 4.50	NA	$ -	$ 4.50	$ 288,474	$ -	2.19%	$ 263	$ -	$ 288,474
Apr-12	-	-	-	-	$ -	NA	NA	$ -	$ 4.69	$ -	$ -	2.19%	$ -	$ -	$ -
May-12	-	53,599	-	53,599		NA	$ 4.41	$ 236,226	$ 4.41	$ -	$ 236,226	2.19%	$ 215	$ 236,226	$ -
Jun-12	53,599	51,870	-	105,469	$ 236,226	$ 4.41	$ 4.45	$ 230,777	$ 4.43	$ -	$ 467,004	2.19%	$ 641	$ 467,004	$ -
Jul-12	105,469	53,599	-	159,068	$ 467,004	$ 4.43	$ 4.49	$ 240,882	$ 4.45	$ -	$ 707,886	2.19%	$ 1,070	$ 707,886	$ -
Aug-12	159,068	42,333	-	201,401	$ 707,886	$ 4.45	$ 4.52	$ 191,270	$ 4.46	$ -	$ 899,156	2.19%	$ 1,464	$ 899,156	$ -
Sep-12	201,401	-	-	201,401	$ 899,156	$ 4.46	NA	$ -	$ 4.46	$ -	$ 899,156	2.19%	$ 1,638	$ 899,156	$ -
Oct-12	201,401	-	-	201,401	$ 899,156	$ 4.46	NA	$ -	$ 4.46	$ -	$ 899,156	2.19%	$ 1,638	$ 899,156	$ -

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	$11,559,846	$ 4.38	NA	$ -	$ 4.38	$ 378,526	$ 11,181,320	2.19%		$ 11,181,320	$ 378,526
Dec-11	2,553,979	-	460,219	2,093,760	$11,181,320	$ 4.38	NA	$ -	$ 4.38	$2,014,840	$ 9,166,479	2.19%		$ 9,166,479	$2,014,840
Jan-12	2,093,760	-	776,610	1,317,150	$ 9,166,479	$ 4.38	NA	$ -	$ 4.38	$3,399,998	$ 5,766,482	2.19%		$ 5,766,482	$3,399,998
Feb-12	1,317,150	-	711,271	605,879	$ 5,766,482	$ 4.38	NA	$ -	$ 4.38	$3,113,945	$ 2,652,537	2.19%		$ 2,652,537	$3,113,945
Mar-12	605,879	-	341,835	264,044	$ 2,652,537	$ 4.38	NA	$ -	$ 4.38	$1,496,552	$ 1,155,985	2.19%		$ 1,155,985	$1,496,552
Apr-12	264,044	391,709	-	655,753	$ 1,155,985	$ 4.38	$ 4.16	$1,628,114	$ 4.25	$ -	$ 2,784,099	2.19%		$ 2,784,099	$ -
May-12	655,753	404,766	-	1,060,520	$ 2,784,099	$ 4.25	$ 4.19	$1,696,295	$ 4.22	$ -	$ 4,480,394	2.19%		$ 4,480,394	$ -
Jun-12	1,060,520	391,709	-	1,452,229	$ 4,480,394	$ 4.22	$ 4.23	$1,657,477	$ 4.23	$ -	$ 6,137,871	2.19%		$ 6,137,871	$ -
Jul-12	1,452,229	404,766	-	1,856,995	$ 6,137,871	$ 4.23	$ 4.28	$1,730,484	$ 4.24	$ -	$ 7,868,355	2.19%		$ 7,868,355	$ -
Aug-12	1,856,995	404,766	-	2,261,761	$ 7,868,355	$ 4.24	$ 4.30	$1,740,052	$ 4.25	$ -	$ 9,608,407	2.19%		$ 9,608,407	$ -
Sep-12	2,261,761	378,679	-	2,640,440	$ 9,608,407	$ 4.25	$ 4.30	$1,627,974	$ 4.26	$ -	$ 11,236,381	2.19%		$ 11,236,381	$ -
Oct-12	2,640,440	-	-	2,640,440	$11,236,381	$ 4.26	NA	$ -	$ 4.26	$ -	$ 11,236,381	2.19%		$ 11,236,381	$ -

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	$ 63,960	$ 6.59	$ 4.96	$ 6,695	$ 6.39	$ 8,626	$ 62,029	2.19%	$ 115	$ 62,029	$ 8,626
Dec-11	9,708	1,395	1,395	9,708	$ 62,029	$ 6.39	$ 6.62	$ 9,234	$ 6.42	$ 8,954	$ 62,308	2.19%	$ 113	$ 62,308	$ 8,954
Jan-12	9,708	2,482	3,453	8,737	$ 62,308	$ 6.42	$ 8.18	$ 20,301	$ 6.78	$ 23,399	$ 59,211	2.19%	$ 111	$ 59,211	$ 23,399
Feb-12	8,737	1,305	1,305	8,737	$ 59,211	$ 6.78	$ 8.02	$ 10,469	$ 6.94	$ 9,055	$ 60,624	2.19%	$ 109	$ 60,624	$ 9,055
Mar-12	8,737	1,395	1,395	8,737	$ 60,624	$ 6.94	$ 5.89	$ 8,218	$ 6.79	$ 9,479	$ 59,364	2.19%	$ 109	$ 59,364	$ 9,479
Apr-12	8,737	4,091	3,120	9,707	$ 59,364	$ 6.79	$ 5.37	$ 21,951	$ 6.34	$ 19,778	$ 61,537	2.19%	$ 110	$ 61,537	$ 19,778
May-12	9,708	1,395	1,395	9,708	$ 61,537	$ 6.34	$ 5.40	$ 7,533	$ 6.22	$ 8,678	$ 60,391	2.19%	$ 111	$ 60,391	$ 8,678
Jun-12	9,708	1,350	1,350	9,708	$ 60,391	$ 6.22	$ 5.44	$ 7,344	$ 6.13	$ 8,270	$ 59,465	2.19%	$ 109	$ 59,465	$ 8,270
Jul-12	9,708	1,395	1,395	9,708	$ 59,465	$ 6.13	$ 5.48	$ 7,649	$ 6.04	$ 8,433	$ 58,681	2.19%	$ 108	$ 58,681	$ 8,433
Aug-12	9,708	1,395	1,395	9,708	$ 58,681	$ 6.04	$ 5.51	$ 7,681	$ 5.98	$ 8,338	$ 58,024	2.19%	$ 106	$ 58,024	$ 8,338
Sep-12	9,708	1,350	1,350	9,708	$ 58,024	$ 5.98	$ 5.51	$ 7,433	$ 5.92	$ 7,992	$ 57,466	2.19%	$ 105	$ 57,466	$ 7,992
Oct-12	9,708	1,395	1,395	9,708	$ 57,466	$ 5.92	$ 5.54	$ 7,728	$ 5.87	$ 8,191	$ 57,002	2.19%	$ 104	$ 57,002	$ 8,191

Revised Schedule 16

LDAC Calculation

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	$0.4395	$0.3283	
3	R-10 Rate at 40% of R5	$3.80	$0.1758	$0.1313	
4	Program Subsidy	$5.70	$0.2637	$0.1970	
5	Average Annual Therms		289	586	875
6					
7	Peak Period RLIAP Subsidy	$34.20	$76.14	$115.48	$225.82
8					
9	**Off Peak Period**				
10	R-5 Base Rates	$9.50	$0.4395	$0.3283	
11	R10 Rate at 40% of R5	$3.80	$0.1758	$0.1313	
12	Program Subsidy	$5.70	$0.2637	$0.1970	
13	Average Annual Therms		254	64	318
14					
15	Off Peak Period RLIAP Subsidy	$34.20	$67.09	$12.53	$113.81
16					
17	Estimated Annual Subsidy				$339.64
18					
19	Number of Estimated 2011/12 Participants				1,138
20					
21	Annual Subsidy times Number of Participants (Ln 17 *Ln 19)				$386,506
22	Prior Year Ending Balance - RLIAP Page 2				($18,911)
23	Estimated Annual Administrative Costs				$0
24	Total Program Costs				$367,594
25					
26	Estimated weather normalized firm therms billed for				
27	the twelve months ended 10/31/12 sales and transportation				61,817,387
28	Attachment 2 to Schedule 10B, Page 1, Line 41, Total Division subtract Special Contracts				
29	**Total Residential Low Income Program Change**				$0.0059

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

													(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)	($16,000)	($427,180)
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	$10,749	$9,513	$286,858
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	$9,925	$12,371	$268,185
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)	($15,956)	($18,858)	($408,507)
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)	($16,369)	($19,391)	($419,806)
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)	($43.72)	($53.52)	($1,133)
18														
19	Ending Balance	($40,583)	($46,016)	($53,196)	($55,468)	($51,254)	($37,232)	($29,303)	($26,206)	($18,690)	($16,781)	($16,000)	($18,911)	($409,640)

Northern Utilities, Inc. -- New Hampshire Division

Energy Efficiency Budget

	Residential	Low-Income	Gen Service	Total
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	$569,197	$132,957	$535,489	$1,237,643

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

	Residential	Low-Income	Gen Service	Total
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	$604,177	$0	$633,465	$1,237,643

DSM Charge Factor Calculation

DSM Charge Factors for Residential Customers

DSM Reconciliation Adjustment	($29,404)	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	$535,099	
Forecasted Annual Throughput Volumes for Residential Customers	16,972,192	Schedule 16 DSM B Nov '11 - Oct '12 Totals- Column 6
Attachment 2 to Schedule 10B, Page 1, Line 41, Res Non-Heat and Res Heat		
Conservation Charge Factor for Residential Customers	**$0.0315**	

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

DSM Reconciliation Adjustment	($214,316)	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	$351,721	
Forecasted Annual Throughput Volumes for C&I Customers	44,845,195	Schedule 16 DSM C Nov '11 - Oct '12 Totals- Column 6
Attachment 2 to Schedule 10B, Page 1 Line 41, G/T 40 through G/T 52		
Conservation Charge Factor for C&I Customers	**$0.0078**	

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	$35,547	$13,813	$2,973	$4,045	$213	($92,147)	($84,896)	3.25%	($234)	($92,381)	990,209	31
June-11	Actual	($92,381)	$0.0359	$21,606	$20,884	$2,973	$507	$27	($89,597)	($90,989)	3.25%	($243)	($89,840)	602,071	30
July-11	Actual	($89,840)	$0.0359	$14,354	$24,549	$2,973	$591	$31	($76,050)	($82,945)	3.25%	($229)	($76,278)	399,823	31
August-11	Actual	($76,278)	$0.0359	$11,515	$19,087	$2,973	$323	$138	($65,273)	($70,776)	3.25%	($195)	($65,469)	320,645	31
September-11	Actual	($65,469)	$0.0359	$12,820	$33,308	$2,973	$384	$126	($41,498)	($53,483)	3.25%	($143)	($41,641)	357,042	30
October-11	Forecast	($41,641)	$0.0359	$17,933	$26,186	$2,973	$986	$123	($29,306)	($35,474)	3.25%	($98)	($29,404)	499,521	31
November-11	Forecast	**($29,404)**	$0.0315	$35,775	$26,186	$2,973	$1,363	$170	($34,487)	($31,945)	3.25%	($85)	($34,572)	1,134,707	30
December-11	Forecast	($34,572)	$0.0315	$61,372	$120,352	$2,973	$6,825	$177	$34,383	($95)	3.25%	($0)	$34,382	1,946,586	31
January-12	Forecast	$34,382	$0.0315	$89,152	$24,231	$3,231	$2,052	$231	($25,024)	$4,679	3.25%	$13	($25,011)	2,827,695	31
February-12	Forecast	($25,011)	$0.0315	$93,986	$29,077	$3,231	$2,645	$249	($83,795)	($54,403)	3.25%	($136)	($83,931)	2,981,038	28
March-12	Forecast	($83,931)	$0.0315	$79,320	$33,923	$3,231	$2,984	$240	($122,872)	($103,402)	3.25%	($285)	($123,158)	2,515,850	31
April-12	Forecast	($123,158)	$0.0315	$67,038	$33,923	$3,231	$2,954	$238	($149,849)	($136,503)	3.25%	($365)	($150,214)	2,126,298	30
May-12	Forecast	($150,214)	$0.0315	$36,302	$24,231	$3,231	$2,130	$240	($156,683)	($153,449)	3.25%	($424)	($157,107)	1,151,412	31
June-12	Forecast	($157,107)	$0.0315	$22,093	$82,385	$3,231	$5,901	$196	($87,487)	($122,297)	3.25%	($327)	($87,814)	700,736	30
July-12	Forecast	($87,814)	$0.0315	$12,599	$19,385	$3,231	$1,170	$165	($76,462)	($82,138)	3.25%	($227)	($76,688)	399,615	31
August-12	Forecast	($76,688)	$0.0315	$10,244	$48,462	$3,231	$2,771	$156	($32,312)	($54,500)	3.25%	($150)	($32,462)	324,918	31
September-12	Forecast	($32,462)	$0.0315	$11,231	$24,231	$3,231	$1,261	$142	($14,828)	($23,645)	3.25%	($63)	($14,892)	356,217	30
October-12	Forecast	($14,892)	$0.0315	$15,988	$24,231	$3,231	$1,230	$139	($2,049)	($8,471)	3.25%	($23)	($2,073)	507,120	31
Nov 11 thru Oct 12 Totals				$535,100	$490,616	$38,256	$33,288	$2,343						16,972,192	

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	Actual	($227,138)	$0.0152	$29,659	$35,277	$2,894	$2,375	$409	($215,843)	($221,491)	3.25%	($592)	($216,434)	1,951,241	30
October-11	Forecast	($216,434)	$0.0152	$32,791	$27,820	$2,894	$4,258	$530	($213,723)	($215,079)	3.25%	($594)	($214,316)	2,157,275	31
November-11	Forecast	**($214,316)**	$0.0078	$27,002	$37,093	$2,871	$3,881	$483	($196,990)	($205,653)	3.25%	($549)	($197,539)	3,442,847	30
December-11	Forecast	($197,539)	$0.0078	$41,067	$37,093	$2,871	$18,347	$476	($179,820)	($188,680)	3.25%	($521)	($180,341)	5,236,112	31
January-12	Forecast	($180,341)	$0.0078	$51,597	$25,834	$2,871	$4,448	$502	($198,283)	($189,312)	3.25%	($523)	($198,806)	6,578,745	31
February-12	Forecast	($198,806)	$0.0078	$50,299	$34,446	$2,871	$5,155	$484	($206,149)	($202,478)	3.25%	($505)	($206,654)	6,413,256	28
March-12	Forecast	($206,654)	$0.0078	$44,856	$25,834	$2,871	$6,116	$493	($216,197)	($211,426)	3.25%	($584)	($216,781)	5,719,288	31
April-12	Forecast	($216,781)	$0.0078	$37,632	$43,057	$2,871	$6,146	$495	($201,844)	($209,312)	3.25%	($559)	($202,403)	4,798,131	30
May-12	Forecast	($202,403)	$0.0078	$22,965	$25,834	$2,871	$4,370	$493	($191,800)	($197,102)	3.25%	($544)	($192,344)	2,928,073	31
June-12	Forecast	($192,344)	$0.0078	$17,242	$60,280	$2,871	$16,199	$537	($129,699)	($161,022)	3.25%	($430)	($130,129)	2,198,369	30
July-12	Forecast	($130,129)	$0.0078	$13,927	$17,223	$2,871	$4,030	$568	($119,365)	($124,747)	3.25%	($344)	($119,709)	1,775,739	31
August-12	Forecast	($119,709)	$0.0078	$12,774	$51,669	$2,871	$10,229	$577	($67,138)	($93,423)	3.25%	($258)	($67,396)	1,628,678	31
September-12	Forecast	($67,396)	$0.0078	$14,356	$51,669	$2,871	$5,239	$591	($21,383)	($44,389)	3.25%	($119)	($21,502)	1,830,427	30
October-12	Forecast	($21,502)	$0.0078	$18,004	$25,834	$2,871	$5,270	$594	($4,936)	($13,219)	3.25%	($36)	($4,972)	2,295,530	31
Nov 11 thru Oct 12 Totals				$351,721	$435,866	$34,452	$89,428	$6,292						44,845,195	

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)	($27,021)
Total ERC Cost to be Recovered	$315,821
Forcasted Firm Sales & Firm Transportation Volumes Attachment 2 to Schedule 10B, Page 1, Line 41, Total Division subtract Special Volumes	61,817,387
ERC Recovery Rate	**$0.0051**

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)
September	Actual	($14,554)	$12,467		($27,021)

Revised Schedule 19

Revised Capacity Allocators

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

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	18,299	36.2%		1,528	16,771
3	RATE G-40 (R)	8,482	84,820	8,065	15.9%		435	7,630
4	RATE G-50 (Q)	1,074	10,740	1,021	2.0%		340	681
5	RATE G-41 (T)	7,609	76,090	7,235	14.3%		541	6,694
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	1,128	2.2%		39	1,089
11	RATE T-50	142	1,420	135	0.3%		80	55
12	RATE T-41	5,614	56,139	5,338	10.5%		270	5,068
13	RATE T-51	407	4,070	387	0.8%		275	112
14	RATE T-42	3,693	36,927	3,511	6.9%		350	3,161
15	RATE T-52	2,083	20,830	1,981	3.9%		804	1,177
16	Total		532,383	50,620	100.0%		8,328	44,610
17			53,238					-
18	Residential Total		195,940	18,630	**36.8%**		1,584	17,046
19	LLF Total		276,580	26,298	52.0%		1,702	24,596
20	HLF Total		59,863	5,692	11.2%		5,042	650
21	Total		532,383	50,620	100.0%		8,328	42,292
22								
23								
24			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
25	Pipeline		2,445,857	13,940	14.62			
26	Storage		15,776,554	16,834	78.10			
27	Peaking		1,208,515	19,847	5.07			
28	Total		19,430,925	50,620	**31.99**	**76.77**		
29								
30								
31								
32			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
33	Pipeline - Baseload		1,461,239	8,328	14.62			
34	Pipeline - Remaining		984,617	5,612	14.62			
35	Storage		15,776,554	16,834	78.10			
36	Peaking		1,208,515	19,847	5.07			
37	Total		19,430,925	50,620	31.99			
38								
39								
40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.			
41	Pipeline - Base	**36.8%**	537,799	3,065	14.62			
42	Pipeline - Remaining	**36.8%**	362,382	2,065	14.62			
43	Storage	**36.8%**	5,806,455	6,196	78.10			
44	Peaking	**36.8%**	444,786	7,304	5.07			
45	Total	**36.8%**	7,151,422	18,630	31.99			

Line			Capacity Cost	MDQ, Dt	$/Dt-Mo.
1	C&I Allocation				
2	Pipeline - Base		923,440	5,263	14.62
3	Pipeline - Remaining		622,236	3,546	14.62
4	Storage		9,970,099	10,638	78.10
5	Peaking		763,729	12,542	5.07
6	Total	**63.2%**	12,279,503	31,990	31.99

Line			Capacity Cost	MDQ, Dt	$/Dt-Mo.
9	LLF - C&I Allocation				
10	Pipeline - Base		233,047	1,328	14.62
11	Pipeline - Remaining		606,221	3,455	14.62
12	Storage		9,713,496	10,364	78.10
13	Peaking		744,073	12,219	5.07
14	Total	**58.1%**	11,296,836	27,367	**34.40**

Line			Capacity Cost	MDQ, Dt	$/Dt-Mo.
17	HLF - C&I Allocation				
18	Pipeline - Base		690,393	3,935	14.62
19	Pipeline - Remaining		16,015	91	14.62
20	Storage		256,603	274	78.10
21	Peaking		19,656	323	5.07
22	Total	**5.1%**	982,667	4,623	**17.71**

Line	Unit Cost	Residential	LLF C&I	HLF C&I
27	Pipeline	$ 14.62	$ 14.62	$ 14.62
28	Storage	$ 78.10	$ 78.10	$ 78.10
29	Peaking	$ 5.07	$ 5.07	$ 5.07
30	Total	$ 31.99	$ 34.40	$ 17.71
31	Checktotal	$ 31.99	$ 34.40	$ 17.71

Line	Load Makeup	Residential	**LLF C&I**	**HLF C&I**
36	Pipeline	27.54%	**17.48%**	**87.09%**
37	Storage	33.26%	**37.87%**	**5.92%**
38	Peaking	39.21%	**44.65%**	**6.98%**
39	Total	100.00%	**100.00%**	**100.00%**

Storage and Peaking

	LLF C&I	**HLF C&I**
Pipeline	**NA**	**NA**
Storage	**45.89%**	**45.89%**
Peaking	**54.11%**	**54.11%**

Line	Supply Makeup	Residential	LLF C&I	HLF C&I	Total
44	Pipeline	36.80%	34.31%	28.88%	100.00%
45	Storage	36.80%	61.57%	1.63%	100.00%
46	Peaking	36.80%	61.57%	1.63%	100.00%

Revised Schedule 21

Allocation of Demand Costs by State

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	$ 8,758,849
Storage Demand	$ 33,297,919
Peaking Demand	$ 1,812,610
Subtotal Demand	$ 43,869,379
Litigation Expense - PNGTS Invoices	$ 414,873
Capacity Release (Credit)	$ (313,490)
Asset Management (Credit)	$ (4,087,000)
Total Net Demand Costs	$ 39,883,762

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	$ 1,619,040	$ 1,058,228	$ 925,104	$ 765,786	$ 1,291,425	$ 857,002	$ 473,782	$ 329,002	$ 283,020	$ 269,103	$ 289,178	$ 598,179	$ 8,758,849

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	$ -	$ -	$ -	$ -	$ -	$ 333,189	$ 244,428	$ 188,733	$ 172,595	$ 167,058	$ 172,180	$ 184,943	$ 1,463,127

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	$ -	$ 4,898,540	$ 12,309,280	$ 9,560,646	$ 5,227,535	$ 1,301,918	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,297,919
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 333,189	$ 244,428	$ 188,733	$ 172,595	$ 167,058	$ 172,180	$ 184,943	$ 1,463,127
TOTAL	$ -	$ 4,898,540	$ 12,309,280	$ 9,560,646	$ 5,227,535	$ 1,635,108	$ 244,428	$ 188,733	$ 172,595	$ 167,058	$ 172,180	$ 184,943	$ 34,761,046

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	$ 1,619,040	$ 1,058,228	$ 925,104	$ 765,786	$ 1,291,425	$ 857,002	$ 473,782	$ 329,002	$ 283,020	$ 269,103	$ 289,178	$ 598,179	$ 8,758,849
51	Storage Incld Inj Fees	$ -	$ 4,898,540	$ 12,309,280	$ 9,560,646	$ 5,227,535	$ 1,635,108	$ 244,428	$ 188,733	$ 172,595	$ 167,058	$ 172,180	$ 184,943	$ 34,761,046
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	$ -	$ -	$ -	$ -	$ -	$ (333,189)	$ (244,428)	$ (188,733)	$ (172,595)	$ (167,058)	$ (172,180)	$ (184,943)	$ (1,463,127)
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	$ 876,443	$ 5,260,944	$ 13,875,737	$ 9,922,837	$ 5,793,371	$ 1,488,095	$ 475,106	$ 330,270	$ 284,344	$ 270,427	$ 290,446	$ 600,870	$ 39,468,889

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%	52.62%
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%	47.38%
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**

		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
70	Maine	$477,063	$2,846,371	$7,231,286	$5,160,327	$3,035,518	$794,423	$249,569	$175,888	$154,703	$149,997	$158,203	$334,255	$20,767,602
71	New Hampshire	$399,380	$2,414,573	$6,644,451	$4,762,510	$2,757,854	$693,672	$225,537	$154,382	$129,642	$120,430	$132,243	$266,614	$18,701,287
72	Total	$ 876,443	$ 5,260,944	$ 13,875,737	$ 9,922,837	$ 5,793,371	$ 1,488,095	$ 475,106	$ 330,270	$ 284,344	$ 270,427	$ 290,446	$ 600,870	$ 39,468,889

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

74	**Maine**	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	
75	Pipeline & Product Demand	$ 881,271	$ 572,542	$ 482,114	$ 398,244	$ 676,660	$ 457,512	$ 248,874	$ 175,213	$ 153,982	$ 149,262	$ 157,512	$ 332,759	$ 4,685,946	53.50%
76	Storage Incld Injection Fees	$ -	$ 2,650,297	$ 6,414,933	$ 4,971,971	$ 2,739,040	$ 872,906	$ 128,396	$ 100,512	$ 93,903	$ 92,662	$ 93,785	$ 102,881	$ 18,261,285	52.53%
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	$ -	$ -	$ -	$ -	$ -	$ (177,874)	$ (128,396)	$ (100,512)	$ (93,903)	$ (92,662)	$ (93,785)	$ (102,881)	$ (790,013)	
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**	$ 477,063	$ 2,846,371	$ 7,231,286	$ 5,160,327	$ 3,035,518	$ 794,423	$ 249,569	$ 175,888	$ 154,703	$ 149,997	$ 158,203	$ 334,255	$ 20,767,602	52.62%

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	$ 737,769	$ 485,686	$ 442,990	$ 367,543	$ 614,765	$ 399,489	$ 224,908	$ 153,789	$ 129,038	$ 119,841	$ 131,666	$ 265,420	$ 4,072,904	46.50%
85	Storage Incld Injection Fees	$ -	$ 2,248,243	$ 5,894,347	$ 4,588,675	$ 2,488,495	$ 762,202	$ 116,032	$ 88,222	$ 78,692	$ 74,397	$ 78,395	$ 82,062	$ 16,499,761	47.47%
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	$ -	$ -	$ -	$ -	$ -	$ (155,315)	$ (116,032)	$ (88,222)	$ (78,692)	$ (74,397)	$ (78,395)	$ (82,062)	$ (673,115)	
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	$ 69,146	$ 69,146	$ 69,146	$ 69,146	$ 69,146	$ 69,146							$ 414,873	
91	**Total Allocated Demand**	$ 468,525	$ 2,483,719	$ 6,713,596	$ 4,831,655	$ 2,826,999	$ 762,817	$ 225,537	$ 154,382	$ 129,642	$ 120,430	$ 132,243	$ 266,614	$ 18,701,287	47.38%

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

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

Revised Schedule 22

Allocation of Commodity Costs by State

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	4,387,843	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	6,931,218	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	6,931,218	5,491,472
9	Total Firm Pipeline Sendout	617,729	568,332	359,160	276,160	525,649	609,348	4,387,843	2,956,378
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 20,529,601	$ 14,141,773
12	NYMEX Price Used for Forecast	$3.541	$3.836	$4.006	$4.028	$3.994	$3.981		
13	NYMEX Price Used for Update	$3.541	$3.836	$4.006	$4.028	$3.994	$3.981		
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	$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 20,529,601	$ 14,141,773
17									
18	Total Pipeline	$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 20,529,601	$ 14,141,773
19	Total Storage	$ 381,888	$ 2,089,744	$ 3,728,211	$ 3,420,390	$ 1,805,801	$ -	$ 11,426,035	$ 11,426,035
20	Total Peaking	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 129,193	$ 79,291
21	Subtotal	$ 3,123,701	$ 4,812,672	$ 5,648,566	$ 4,942,871	$ 4,436,093	$ 2,683,196	$ 32,084,829	$ 25,647,099
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	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981		
28	NYMEX Price Used for Update	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981		
29	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
30	Futures Hedging (Gain)/Loss - Allocate	$ 133,160	$ 246,840	$ 300,340	$ 305,840	$ 241,420	$ 108,940	$ 1,411,790	$ 1,336,540
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	-	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981		
35	NYMEX Price Used for Update	$ 3.541	$ 3.836	$ 4.006	$ 4.028	$ 3.994	$ 3.981		
36	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 20,529,601	$ 14,141,773
41	Average Supply Cost ($/MMBtu)	$ 4.425	$ 4.775	$ 5.282	$ 5.480	$ 4.986	$ 4.371		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 20,529,601	$ 14,141,773
46	Total Storage	$ 381,888	$ 2,089,744	$ 3,728,211	$ 3,420,390	$ 1,805,801	$ -	$ 11,426,035	$ 11,426,035
47	Total Peaking	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 129,193	$ 79,291
48	Firm Sales Variable Costs Excld Hedge	$ 3,123,701	$ 4,812,672	$ 5,648,566	$ 4,942,871	$ 4,436,093	$ 2,683,196	$ 32,084,829	$ 25,647,099
49	Plus Hedging (Gain)/Loss	$ 133,160	$ 246,840	$ 300,340	$ 305,840	$ 241,420	$ 108,940	$ 1,411,790	$ 1,336,540
50	Total Firm Sales Variable Costs	$ 3,256,861	$ 5,059,512	$ 5,948,906	$ 5,248,711	$ 4,677,513	$ 2,792,136	$ 33,496,619	$ 26,983,639

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	$ 1,297,679	$ 1,279,884	$ 900,075	$ 712,395	$ 1,246,555	$ 1,276,142	$ 9,754,635	$ 6,712,730
Hedging (Gains) Losses	$ 63,222	$ 116,407	$ 142,506	$ 143,964	$ 114,828	$ 52,197	$ 669,028	$ 633,126
Storage	$ 181,315	$ 985,503	$ 1,768,976	$ 1,610,036	$ 858,906	$ -	$ 5,404,736	$ 5,404,736
Peaking	$ 4,096	$ 4,223	$ 11,102	$ 4,262	$ 4,509	$ 9,476	$ 61,441	$ 37,668
Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Maine Commodity Costs	$ 1,546,312	$ 2,386,017	$ 2,822,660	$ 2,470,657	$ 2,224,798	$ 1,337,816	$ 15,889,839	$ 12,788,259
Maine Inventory Finance Costs	$ 758	$ 1,230	$ 1,470	$ 1,248	$ 1,082	$ 630	$ 6,419	$ 6,419
Total Maine Variable Costs	$ 1,547,070	$ 2,387,247	$ 2,824,130	$ 2,471,906	$ 2,225,881	$ 1,338,445	$ 15,896,259	$ 12,794,679
New Hampshire								
Firm Sales Pipeline Commodity Excld Hedge	$ 1,435,508	$ 1,434,090	$ 996,881	$ 801,031	$ 1,374,257	$ 1,387,276	$ 10,774,966	$ 7,429,043
Hedging (Gains) Losses	$ 69,938	$ 130,433	$ 157,834	$ 161,876	$ 126,592	$ 56,743	$ 742,762	$ 703,414
Storage	$ 200,573	$ 1,104,241	$ 1,959,235	$ 1,810,354	$ 946,895	$ -	$ 6,021,299	$ 6,021,299
Peaking	$ 4,530	$ 4,731	$ 12,297	$ 4,793	$ 4,970	$ 10,302	$ 67,752	$ 41,623
New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 1,710,549	$ 2,673,495	$ 3,126,246	$ 2,778,054	$ 2,452,714	$ 1,454,321	$ 17,606,780	$ 14,195,380
New Hampshire Inventory Finance Costs	$ 839	$ 1,383	$ 1,629	$ 1,409	$ 1,192	$ 679	$ 7,131	$ 7,131
Total New Hampshire Variable Costs	$ 1,711,388	$ 2,674,879	$ 3,127,876	$ 2,779,463	$ 2,453,906	$ 1,454,999	$ 17,613,910	$ 14,202,510
Northern Utilities								
Firm Sales Pipeline Commodity Excld Hedge	$ 2,733,187	$ 2,713,974	$ 1,896,956	$ 1,513,426	$ 2,620,812	$ 2,663,418	$ 20,529,601	$ 14,141,773
Hedging (Gains) Losses	$ 133,160	$ 246,840	$ 300,340	$ 305,840	$ 241,420	$ 108,940	$ 1,411,790	$ 1,336,540
Storage	$ 381,888	$ 2,089,744	$ 3,728,211	$ 3,420,390	$ 1,805,801	$ -	$ 11,426,035	$ 11,426,035
Peaking	$ 8,626	$ 8,954	$ 23,399	$ 9,055	$ 9,479	$ 19,778	$ 129,193	$ 79,291
Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Northern Commodity Costs	$ 3,256,861	$ 5,059,512	$ 5,948,906	$ 5,248,711	$ 4,677,513	$ 2,792,136	$ 33,496,619	$ 26,983,639
Northern Inventory Finance Costs	$ 1,597	$ 2,614	$ 3,100	$ 2,658	$ 2,274	$ 1,309	$ 13,550	$ 13,550
Total Northern Variable Costs	$ 3,258,458	$ 5,062,126	$ 5,952,006	$ 5,251,368	$ 4,679,787	$ 2,793,445	$ 33,510,169	$ 26,997,189

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
Inventory Finance Charge	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**TOTAL**
Storage	$ 1,651	$ 1,601	$ 1,285	$ 773	$ 263	$ -	$ 12,239
Peaking	$ 115	$ 113	$ 111	$ 109	$ 109	$ 110	$ 1,311
Total	$ 1,766	$ 1,714	$ 1,396	$ 882	$ 372	$ 110	$ 13,550
Inventory Finance Charge Allocation by Jurisdiction							
Maine	$ 838	$ 808	$ 662	$ 415	$ 177	$ 53	$ 6,419
New Hampshire	$ 927	$ 906	$ 734	$ 467	$ 195	$ 57	$ 7,131
Total	$ 1,766	$ 1,714	$ 1,396	$ 882	$ 372	$ 110	$ 13,550

Inventory Finance Charge Allocation by Month

Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
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	$ 758	$ 1,230	$ 1,470	$ 1,248	$ 1,082	$ 630	$ 6,419	$ 6,419
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	$ 839	$ 1,383	$ 1,629	$ 1,409	$ 1,192	$ 679	$ 7,131	$ 7,131

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

Revised Schedule 23

Supporting Detail to Proposed Tariff Sheets

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

		Winter	Summer	Total	
1	Demand	$ 14,697,036	$ 882,548	$ 15,579,584	Schedule 1A, LN 80
2	Commodity	$ 14,202,510	$ 3,411,400	$ 17,613,910	Schedule 1B, LN 43
3	Total	$ 28,899,546	$ 4,293,948	$ 33,193,494	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	$0.5136	$0.1182		LN 1 / LN 5
9	Average Commodity Rate	$0.4963	$0.4569		LN 2 / LN 5
10	Average Rate	$1.0100	$0.5751		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 7,359,000	$ 425,069	$ 7,784,068	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 6,950,432	$ 406,610	$ 7,357,042	LN 8 * LN 6
15	**Demand Reallocation:**	$ 408,568	$ 18,458	$ 427,026	LN 13 - LN 14
16	**HLF Allocation**	$ 44,348	$ 5,002	$ 49,350	LN 15 * LN 20
17	**LLF Allocation**	$ 364,220	$ 13,457	$ 377,676	LN 15 * LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	10.85%	27.10%		Schedule 10A, LN 173
21	LLF	89.15%	72.90%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 6,711,328	$ 1,571,739	$ 8,283,067	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 6,716,564	$ 1,571,745	$ 8,288,309	LN 6 * LN 9
25	**Commodity Reallocation:**	$ (5,236)	$ (6)	$ (5,242)	LN 23 - LN 24
26	**HLF Allocation**	$ (930)	$ (2)	$ (932)	LN 25 / LN 30
27	**LLF Allocation**	$ (4,306)	$ (3)	$ (4,309)	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	17.76%	43.73%		Schedule 10C, LN 143
31	LLF	82.24%	56.27%		Schedule 10C, LN 144

Variance Analysis

Initial vs. Revised Filing

Northern Utilities New Hampshire Division
Period Covered: November 1, 2011 - October 31, 2012
Effect of Revision - Variance Analysis

		2011 -2012 Winter (Initial Filing)			Forecast 2011-2012 Winter (Revised Filing)			Variance		
1	Therm Sales	28,614,458			28,614,458			0		
2 3 4		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
5										
6	Demand Charges		$ 16,876,488	$ 0.5898		$ 16,309,451	0.5700		$ (567,037)	$ (0.0198)
7										
8	Purchased Gas		7,934,188	0.2773		7,429,043	0.2596		$ (505,145)	$ (0.0177)
9										
10	Storage & Peaking Gas		6,076,270	0.2123		6,062,922	0.2119		$ (13,347)	$ (0.0005)
11										
12	Hedging (Gain)/Loss		506,830	0.0177		703,414	0.0246		$ 196,584	$ 0.0069
13										
14										
15	Total Volumes and Cost	$ -	$ 31,393,776	$ 1.0971	$ -	$ 30,504,831	$ 1.0661	$ -	$ (888,945)	$ (0.0311)
16										
17	Prior Period Balance		$973,628	$ 0.0340		$ 973,628	$ 0.0340		$ -	$ -
18	NHPUC Consultant Costs		-			$ -	$ -		$ -	$ -
19	Interest		$73,830	$ 0.0026		71,698	$ 0.0025		$ (2,132)	$ (0.0001)
20	Refunds from Suppliers		-	$ -		-	$ -		-	$ -
21										
22	Prior Period Adjustment									
23	Interruptible Sales Margin		-	$ -		-	$ -		-	$ -
24	Capacity Release		(1,612,415)	$ (0.0563)		(1,612,415)	$ (0.0563)		$ -	$ -
25	Working Capital Allowance		(10,682)	$ (0.0004)		(11,415)	$ (0.0004)		$ (733)	$ (0.0000)
26	Bad Debt Allowance		379,392	$ 0.0133		379,392	$ 0.0133		$ -	$ -
27	Fuel Inventory Financing		7,294	$ 0.0003		7,131	$ 0.0002		$ (163)	$ (0.0000)
28	Local Production and Storage		349,700	$ 0.0122		349,700	$ 0.0122		$ -	$ -
29	Misc Overhead		349,601	$ 0.0122		349,601	$ 0.0122		$ -	$ -
30										
31	Total Anticipated Indirect Cost of Gas		$510,349	$ 0.0178		507,320	$ 0.0177		$ (3,028)	$ (0.0001)
32	Total Adjusted Cost	-	$31,904,124	$ 1.1149		$31,904,124	$ 1.0837		$ -	$ (0.0312)