Schedules 1A and 1B

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	$ 3,828,257
3	Storage	$ 13,166,443
4	Peaking	$ 1,606,069
5	Total Gross Demand Cost	$ 18,600,768
6		
7	Capacity Assignment Demand Revenue Estimate	$ 3,397,784
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 18,600,768
9	Capacity Assignment as % of Total Gross Demand Cost	18.27%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 699,304
14	Storage	$ 2,405,101
15	Peaking	$ 293,379
16	Total Capacity Assignment Credit	$ 3,397,784
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 3,128,953
21	Storage	$ 10,761,342
22	Peaking	$ 1,312,690
23	Total Net Demand Cost (Less Capacity Assignment)	$ 15,202,984
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,229
28	Less 18.27% NH Transp. Capacity Assignment	(2,051)
29	Net Pipeline MDQ	9,178
30		
31	Net Pipeline MDQ	9,178
32	Less: Firm Sales Base Use	2,735
33	Remaining Pipeline MDQ	6,443
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$340.92
37		
38		**Costs**
39	Pipeline & Product Demand	$ 3,128,953
40	Less: Base Pipeline Use	$ 932,444
41	Remaining Pipeline Use	$ 2,196,509

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**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 18.27% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

45	**All Months**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
46	Remaining Load for All Months	2,780,965	4,457,655	5,850,045	4,833,516	3,468,685	1,731,269
47	Rank	5	3	1	2	4	6
48	% Max Month	47.54%	76.20%	100.00%	82.62%	59.29%	29.59%
49	PR	3.59%	5.64%	17.38%	3.21%	2.94%	2.59%
50	CumPR	7.98%	16.55%	37.14%	19.76%	10.92%	4.39%

51

52	**Peak Months Only**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
53	Remaining Load for Peak Months Only	2,780,965	4,457,655	5,850,045	4,833,516	3,468,685	1,731,269
54	Rank	5	3	1	2	4	6
55	% Max Month	47.54%	76.20%	100.00%	82.62%	59.29%	29.59%
56	PR	3.59%	5.64%	17.38%	3.21%	2.94%	4.93%
57	CumPR	8.52%	17.10%	37.68%	20.31%	11.46%	4.93%

58

59 **DEMAND COST PR ALLOCATORS**

60		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
62	Pipeline - Remaining	7.98%	16.55%	37.14%	19.76%	10.92%	4.39%
63	Storage & Peaking	7.98%	16.55%	37.14%	19.76%	10.92%	4.39%
64	Capacity Release	8.52%	17.10%	37.68%	20.31%	11.46%	4.93%
65	Interr. Margins & Off Sys Sales	8.52%	17.10%	37.68%	20.31%	11.46%	4.93%

66

67 **DEMAND COSTS ALLOCATED TO MONTHS**

68		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
69	Pipeline - Base	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 77,704
70	Pipeline - Remaining	$ 175,218	$ 363,548	$ 815,785	$ 434,110	$ 239,772	$ 96,392
71	Total Pipeline	$ 252,922	$ 441,252	$ 893,489	$ 511,814	$ 317,476	$ 174,096
72							
73	Storage & Peaking	$ 963,159	$ 1,998,394	$ 4,484,303	$ 2,386,268	$ 1,318,008	$ 529,861
74							
75	Less Credits to Demand Cost						
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 397,147	$ 796,767	$ 1,756,372	$ 946,493	$ 534,126	$ 229,887
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
79							
80	Total Direct Demand Costs	$ 818,933	$ 1,642,879	$ 3,621,420	$ 1,951,589	$ 1,101,359	$ 474,070

81

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

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

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

		May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer
45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**
46	Remaining Load for All Months	488,265	129,675	0	18,525	135,105	823,825	24,717,532	23,122,136	1,595,396
47	Rank	8	10	12	11	9	7			
48	% Max Month	8.35%	2.22%	0.00%	0.32%	2.31%	14.08%			
49	PR	0.75%	0.19%	0.00%	0.03%	0.01%	0.82%	37.14%		
50	CumPR	0.98%	0.22%	0.00%	0.03%	0.23%	1.80%	100.00%	96.74%	3.26%
51										
52	**Peak Months Only**							**Annual**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only							23,122,136	23,122,136	
54	Rank									
55	% Max Month									
56	PR							37.68%		
57	CumPR							100.00%	100.00%	0.00%
58										
59	**DEMAND COST PR ALLOCATORS**									
60		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
62	Pipeline - Remaining	0.98%	0.22%	0.00%	0.03%	0.23%	1.80%	100.00%	96.74%	3.26%
63	Storage & Peaking	0.98%	0.22%	0.00%	0.03%	0.23%	1.80%	100.00%	96.74%	3.26%
64	Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
66										

67 **DEMAND COSTS ALLOCATED TO MONTHS**

68		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**	**Winter**	**Summer**
69	Pipeline - Base	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 932,444	$ 466,222	$ 466,222	50.00%	50.00%
70	Pipeline - Remaining	$ 21,607	$ 4,806	$ -	$ 632	$ 5,032	$ 39,606	$ 2,196,509	$ 2,124,826	$ 71,684	96.74%	3.26%
71	Total Pipeline	$ 99,311	$ 82,509	$ 77,704	$ 78,336	$ 82,736	$ 117,310	$ 3,128,953	$ 2,591,047	$ 537,905	82.81%	17.19%
72												
73	Storage & Peaking	$ 118,773	$ 26,416	$ -	$ 3,476	$ 27,662	$ 217,712	$ 12,074,031	$ 11,679,992	$ 394,039	96.74%	3.26%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$4,660,791	$ 4,660,791	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 218,084	$ 108,926	$ 77,704	$ 81,812	$ 110,397	$ 335,022	$ 10,542,193	$ 9,610,249	$ 931,944	91.16%	8.84%
81												
82	Indirect Demand Costs/(Credits)											
83	Miscellaneous Overhead							$ 411,600	$ 333,160	$ 78,440	80.94%	19.06%
84	Local Production & Storage							$ 307,762	$ 307,762	$ -	100.00%	0.00%
85	Subtotal							$ 719,362	$ 640,922	$ 78,440	89.10%	10.90%

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	Less Credits to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	Schedule 1A, Page 6, Line 6
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

		A Total	B Capacity Assigned	C Sales	D Total	E Capacity Assigned	F Sales
1	Asset Management	($5,535,367)	($924,882)	($4,610,485)	Schedule 21, Line 89	Schedule 5B, Page 5	A - B
2	Capacity Release Revenues	($70,950)	$0	($70,950)	Schedule 21, Line 88		A - B
3	PNGTS Litigation	$22,988	$2,344	$20,644	Schedule 5B, Page 6	Schedule 5B, Page 5	A - B
4	Total NH Cap Rel and Asset Management	($5,583,329)	($922,538)	($4,660,791)			Sum (LN1 + LN 2 + LN 5)

Northern Utilities, Inc.
New Hampshire Division
Schedule 1B
Page 1 of 2

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	3,532,603	4,223,974	3,341,500	3,037,412	3,268,939	2,529,179	26,503,549	19,933,607
2	New Hampshire Sales Storage	62,166	1,074,326	2,609,366	2,098,108	1,040,473	0	6,884,440	6,884,440
3	New Hampshire Sales Peaking	6,599	6,832	746,444	463,169	6,766	14,513	1,286,108	1,244,323
4	Total New Hampshire Firm Sales Sendout	3,601,369	5,305,131	6,697,310	5,598,689	4,316,178	2,543,692	34,674,097	28,062,369
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	3,601,369	5,305,131	6,697,310	5,598,689	4,316,178	2,543,692	34,674,097	28,062,369
9	Total Firm Sales	3,579,105	5,272,786	6,656,691	5,564,807	4,289,774	2,527,995	34,457,951	27,891,158
10	Difference (LAUF & Company Use)	22,264	32,345	40,619	33,883	26,404	15,697	216,146	171,211
11	Percent Difference	0.62%	0.61%	0.61%	0.61%	0.61%	0.62%	0.62%	0.61%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 1,964,423	$ 2,341,127	$ 1,998,407	$ 1,814,040	$ 1,939,482	$ 1,059,471	$ 13,826,648	$ 11,116,950
15	New Hampshire Hedging (Gains) Losses	$ 16,513	$ 29,923	$ 34,243	$ 31,078	$ 22,684	$ 10,351	$ 144,792	$ 144,792
16	New Hampshire Total Storage	$ 24,700	$ 426,855	$ 1,035,086	$ 832,106	$ 412,193	$ -	$ 2,730,940	$ 2,730,940
17	New Hampshire Total Peaking	$ 4,465	$ 4,811	$ 1,217,289	$ 745,219	$ 5,023	$ 10,039	$ 2,014,233	$ 1,986,847
18	New Hampshire Inventory Finance Charge	$ 665	$ 1,066	$ 1,398	$ 1,155	$ 829	$ 414	$ 5,527	$ 5,527
19	Total New Hampshire Sales Variable Costs	$ 2,010,766	$ 2,803,782	$ 4,286,423	$ 3,423,599	$ 2,380,212	$ 1,080,275	$ 18,722,140	$ 15,985,057
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,994,253	$ 2,773,859	$ 4,252,181	$ 3,392,520	$ 2,357,528	$ 1,069,924	$ 18,577,348	$ 15,840,264
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 2,010,766	$ 2,803,782	$ 4,286,423	$ 3,423,599	$ 2,380,212	$ 1,080,275	$ 18,722,140	$ 15,985,057
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.5561	$ 0.5542	$ 0.5981	$ 0.5972	$ 0.5933	$ 0.4189	$ 0.5217	$ 0.5577
27	New Hampshire Hedging (Gains) Losses	$ 0.0047	$ 0.0071	$ 0.0102	$ 0.0102	$ 0.0069	$ 0.0041	$ 0.0055	$ 0.0073
28	New Hampshire Storage Excld Inventory Finance Costs	$ 0.3973	$ 0.3973	$ 0.3967	$ 0.3966	$ 0.3962	$ -	$ 0.3967	$ 0.3967
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.6766	$ 0.7042	$ 1.6308	$ 1.6090	$ 0.7424	$ 0.6917	$ 1.5661	$ 1.5967
30	New Hampshire Inventory Finance Costs per Dth Stor and	$ 0.0097	$ 0.0010	$ 0.0004	$ 0.0005	$ 0.0008	$ 0.0285	$ 0.0007	$ 0.0007
31	Weighted Average Cost per Dth Sendout	$ 0.5583	$ 0.5285	$ 0.6400	$ 0.6115	$ 0.5515	$ 0.4247	$ 0.5399	$ 0.5696
32									
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	820,515	847,865	847,865	765,814	847,865	812,691	9,956,578	4,942,614
37	Base Commodity Cost Excld Hedging	$ 456,275	$ 469,927	$ 507,071	$ 457,368	$ 503,044	$ 340,436	$ 4,795,463	$ 2,734,121
38	Base Hedging Commodity Cost	$ 3,835	$ 6,006	$ 8,689	$ 7,836	$ 5,884	$ 3,326	$ 35,576	$ 35,576
39	Remaining Commodity Excld Hedging	$ 1,537,978	$ 2,303,932	$ 3,745,109	$ 2,935,152	$ 1,854,484	$ 729,488	$ 13,781,886	$ 13,106,143
40	Remaining Hedging Commodity	$ 12,678	$ 23,917	$ 25,554	$ 23,243	$ 16,800	$ 7,025	$ 109,216	$ 109,216
41	Total Commodity Excld Hedging	$ 1,994,253	$ 2,773,859	$ 4,252,181	$ 3,392,520	$ 2,357,528	$ 1,069,924	$ 18,577,348	$ 15,840,264
42	Total Hedging	$ 16,513	$ 29,923	$ 34,243	$ 31,078	$ 22,684	$ 10,351	$ 144,792	$ 144,792
43	Total Commodity (Incl Hedging)	$ 2,010,766	$ 2,803,782	$ 4,286,423	$ 3,423,599	$ 2,380,212	$ 1,080,275	$ 18,722,140	$ 15,985,057

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

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

Schedule 2

Estimated Delivered City-Gate Commodity Costs and Volumes November 2013 through April 2014			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage	$759,520	193,442	$3.926
Tenn Zone 4 Spot	$887,485	224,755	$3.949
Washington 10 Storage	$10,126,992	2,548,803	$3.973
Tennessee Production	$4,679,966	1,147,820	$4.077
Chicago	$3,791,653	871,493	$4.351
TGP Zone 6	$252,686	56,894	$4.441
Algonquin Receipts	$844,050	188,901	$4.468
Niagara	$1,599,104	347,191	$4.606
Iroquois Receipts	$512,833	86,760	$5.911
PNGTS	$929,923	135,424	$6.867
LNG	$69,852	9,860	$7.084
PNGTS Delivered	$1,099,553	135,424	$8.119
Lewiston Baseload	$8,776,512	1,026,500	$8.550
Peaking Supply 3	$4,037,149	249,125	$16.205
Total Delivered Commodity Cost	$38,367,279	7,222,392	$5.312

Schedules 3A &3B

Northern Utilities

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

			Summer						Winter						
	Sales Revenues								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
2	Residential Heat & Non Heat								1,782,979	2,626,708	3,316,119	2,772,182	2,137,008	1,259,354	13,894,351
3	Sales HLF Classes								266,142	392,084	494,991	413,799	318,987	187,982	2,073,984
4	Sales LLF Classes								1,529,984	2,253,994	2,845,581	2,378,826	1,833,779	1,080,659	11,922,823
5	Total								3,579,105	5,272,786	6,656,691	5,564,807	4,289,774	2,527,995	27,891,158
6	Rates														
7	Residential Heat & Non Heat CGA								$0.8567	$0.8567	$0.8567	$0.8567	$0.8567	$0.8567	
8	Sales HLF Classes CGA								$0.7764	$0.7764	$0.7764	$0.7764	$0.7764	$0.7764	
9	Sales LLF Classes CGA								$0.8706	$0.8706	$0.8706	$0.8706	$0.8706	$0.8706	
10	Revenues														
11	Residential Heat & Non Heat								$ (1,527,478)	$ (2,250,301)	$ (2,840,919)	$ (2,374,929)	$ (1,830,775)	$ (1,078,889)	$(11,903,291)
12	Sales HLF Classes								$ (206,633)	$ (304,414)	$ (384,311)	$ (321,273)	$ (247,662)	$ (145,949)	$ (1,610,241)
13	Sales LLF Classes								$ (1,332,004)	$ (1,962,327)	$ (2,477,363)	$ (2,071,006)	$ (1,596,488)	$ (940,822)	$(10,380,009)
14	Total Sales Revenues								$ (3,066,115)	$ (4,517,042)	$ (5,702,593)	$ (4,767,207)	$ (3,674,925)	$ (2,165,660)	$(23,893,542)
15															

			Summer						Winter						
16															
17	**Gas Costs and Credits**		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18			May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline		$ 215,493	$ 215,493	$ 215,493	$ 217,205	$ 217,205	$ 217,205	$ 215,493	$ 215,493	$ 215,493	$ 215,493	$ 215,493	$ 215,493	$ 2,591,047
21	Storage		$ 461,041	$ 461,041	$ 461,041	$ 464,035	$ 464,035	$ 464,035	$ 1,434,037	$ 1,434,037	$ 1,434,037	$ 1,434,037	$ 1,434,037	$ 461,041	$ 10,406,454
22	Peaking		$ 53,104	$ 53,104	$ 53,104	$ 56,506	$ 56,506	$ 56,506	$ 171,661	$ 181,509	$ 181,509	$ 181,509	$ 171,661	$ 53,104	$ 1,269,785
23	Total Demand Costs		$ 729,638	$ 729,638	$ 729,638	$ 737,746	$ 737,746	$ 737,746	$ 1,821,190	$ 1,831,039	$ 1,831,039	$ 1,831,039	$ 1,821,190	$ 729,638	$ 14,267,287
24	NUI Commodity Costs														
25	NUI Total Pipeline Volumes								722,652	862,488	688,352	622,370	673,991	534,134	4,103,987
26	Pipeline Costs Modeled in Sendout™								$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 22,868,912
27	NYMEX Price Used for Forecast								$ 3.6660	$ 3.8300	$ 3.9120	$ 3.9120	$ 3.8770	$ 3.8090	
28	NYMEX Price Used for Update								$ 3.6660	$ 3.8300	$ 3.9120	$ 3.9120	$ 3.8770	$ 3.8090	
29	Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
30	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
31	Updated Pipeline Costs								$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	
32	Interruptible Volumes - NH								0	0	0	0	0	0	
33	Average Supply Cost ($/MMBtu)								$ 5.56	$ 5.54	$ 5.98	$ 5.97	$ 5.93	$ 4.19	
34	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Updated Pipeline Costs								$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	
36	New Hampshire Allocated Percentage								48.88%	48.97%	48.54%	48.80%	48.50%	47.35%	
37	NH Updated Pipeline Costs								$ 1,964,423	$ 2,341,127	$ 1,998,407	$ 1,814,040	$ 1,939,482	$ 1,059,471	$ 11,116,950
38	Hedging (Gain)/Loss Estimate														
39	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
40	NYMEX NG Futures Contracts								19	28	32	28	25	15	
41	Average Purchase Price								$ 3.8438	$ 4.0482	$ 4.1324	$ 4.1394	$ 4.0641	$ 3.9547	
42	NYMEX Price Used for Forecast								$ 3.6660	$ 3.8300	$ 3.9120	$ 3.9120	$ 3.8770	$ 3.8090	
43	NYMEX Price Used for Update								$ 3.6660	$ 3.8300	$ 3.9120	$ 3.9120	$ 3.8770	$ 3.8090	
44	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
45	NUI Futures Hedging (Gain)/Loss - Allocate								$ 33,780	$ 61,100	$ 70,540	$ 63,680	$ 46,770	$ 21,860	$ 297,730
46	New Hampshire Allocated Percentage								48.88%	48.97%	48.54%	48.80%	48.50%	47.35%	
47	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 16,513	$ 29,923	$ 34,243	$ 31,078	$ 22,684	$ 10,351	$ 144,792
48	Price Triggered NYMEX Contracts (NH Only)														
49	NYMEX NG Futures Contracts								0	0	0	0	0	0	
50	Average Purchase Price								$ -	$ -	$ -	$ -	$ -	$ -	
51	NYMEX Price Used for Forecast								$ 3.8300	$ 3.8300	$ 3.9120	$ 3.9120	$ 3.8770	$ 3.8090	
52	NYMEX Price Used for Update								$ 3.8300	$ 3.8300	$ 3.9120	$ 3.9120	$ 3.8770	$ 3.8090	
53	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
54	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	New Hampshire Allocated Percentage								100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
56	NH Futures Hedging (Gain)/Loss, Price Triggered								$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	NH Commodity Costs														
58	Pipeline Excl Hedging								$ 1,964,423	$ 2,341,127	$ 1,998,407	$ 1,814,040	$ 1,939,482	$ 1,059,471	$ 11,116,950
59	Hedging (Gain)/Loss Estimate								$ 16,513	$ 29,923	$ 34,243	$ 31,078	$ 22,684	$ 10,351	$ 144,792
60	Storage								$ 24,700	$ 426,855	$ 1,035,086	$ 832,106	$ 412,193	$ -	$ 2,730,940
61	Peaking								$ 4,465	$ 4,811	$ 1,217,289	$ 745,219	$ 5,023	$ 10,039	$ 1,986,847
62	Total Commodity Costs								$ 2,010,101	$ 2,802,717	$ 4,285,025	$ 3,422,443	$ 2,379,382	$ 1,079,861	$ 15,979,529
63	Inventory Finance Charge		$ 142	$ 290	$ 430	$ 564	$ 700	$ 740	$ 726	$ 732	$ 600	$ 365	$ 163	$ 73	$ 5,527

64	Asset Management and Capacity Release														
65	NUI AMA Revenue								$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	($11,805,500)
66	PNGTS Litigation Cost								$ 3,441	$ 3,441	$ 3,441	$ 3,441	$ 3,441	$ 3,441	$20,644
67	NUI Capacity Release								$ (25,116)	$ (25,116)	$ (25,116)	$ (25,116)	$ (25,116)	$ (25,116)	$ (150,697)
68	NUI AMA Rev & Cap. Release Subtotal								$ (1,989,259)	$ (1,989,259)	$ (1,989,259)	$ (1,989,259)	$ (1,989,259)	$ (1,989,259)	$(11,935,552)
69	NH AMA Revenue								$ (768,414)	$ (768,414)	$ (768,414)	$ (768,414)	$ (768,414)	$ (768,414)	($4,610,485)
70	NH Capacity Release								$ (11,825)	$ (11,825)	$ (11,825)	$ (11,825)	$ (11,825)	$ (11,825)	($70,950)
71	NH Total Asset Management and Capacity Release								$ (776,799)	$ (776,799)	$ (776,799)	$ (776,799)	$ (776,799)	$ (776,799)	$ (4,660,791)
72															
73	**Total Anticipated Direct Cost of Gas**		$ 729,780	$ 729,927	$ 730,068	$ 738,310	$ 738,447	$ 738,487	$ 3,055,219	$ 3,857,689	$ 5,339,865	$ 4,477,049	$ 3,423,938	$ 1,032,774	$ 25,591,552
74			Winter						Summer						
75									(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
76		Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
77	Working Capital														
78	Total Anticipated Direct Cost of Gas		$ 729,780	$ 729,927	$ 730,068	$ 738,310	$ 738,447	$ 738,487	$ 3,162,040	$ 3,964,509	$ 5,446,686	$ 4,583,869	$ 3,530,758	$ 1,139,594	$ 26,232,474
79	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%	0.0824%	
80	Working Capital Allowance		$ 601	$ 601	$ 601	$ 608	$ 608	$ 608	$ 2,604	$ 3,265	$ 4,486	$ 3,775	$ 2,908	$ 939	$ 21,606
81	Beginning Period Working Capital Balance		$ (1,852)	$ (1,255)	$ (657)	$ (56)	$ 553	$ 1,163	$ 1,775	$ 4,388	$ 7,670	$ 12,183	$ 15,996	$ 18,951	
82	End of Period Working Capital Allowance		$ (1,251)	$ (654)	$ (55)	$ 552	$ 1,161	$ 1,771	$ 4,380	$ 7,653	$ 12,156	$ 15,958	$ 18,904	$ 19,890	
83	Interest		$ (4)	$ (3)	$ (1)	$ 1	$ 2	$ 4	$ 8	$ 16	$ 27	$ 38	$ 47	$ 53	$ 189
84	End of period with Interest	$ (1,852)	$ (1,255)	$ (657)	$ (56)	$ 553	$ 1,163	$ 1,775	$ 4,388	$ 7,670	$ 12,183	$ 15,996	$ 18,951	$ 19,943	
85	Bad Debt														
89															$ -
91	Bad Debt Allowance								$ 43,861.50	$ 43,861.50	$ 43,861.50	$ 43,861.50	$ 43,861.50	$ 43,861.50	$ 263,169
92	Beginning Period Bad Debt Balance		$ (71,949)	$ (72,144)	$ (72,339)	$ (72,535)	$ (72,732)	$ (72,929)	$ (73,126)	$ (29,403)	$ 14,438	$ 58,398	$ 102,477	$ 146,675	
93	End of Period Bad Debt Balance		$ (71,949)	$ (72,144)	$ (72,339)	$ (72,535)	$ (72,732)	$ (72,929)	$ (29,265)	$ 14,458	$ 58,299	$ 102,259	$ 146,339	$ 190,537	
94	Interest		$ (195)	$ (195)	$ (196)	$ (196)	$ (197)	$ (198)	$ (139)	$ (20)	$ 98	$ 218	$ 337	$ 457	$ (226)
95	End of Period Bad Debt Balance with Interest	$ (71,949)	$ (72,144)	$ (72,339)	$ (72,535)	$ (72,732)	$ (72,929)	$ (73,126)	$ (29,403)	$ 14,438	$ 58,398	$ 102,477	$ 146,675	$ 190,994	
96	Local Production and Storage Capacity								$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 307,762
97	Miscellaneous Overhead								$ 55,527	$ 55,527	$ 55,527	$ 55,527	$ 55,527	$ 55,527	$ 333,160
98	Refunds								$ (74,841)	$ (74,841)	$ (74,841)	$ (74,841)	$ (74,841)	$ (74,841)	$ (449,048)
99	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
100	Beginning Balance Over/Under Collection		$ (2,128,249)	$ (1,403,245)	$ (676,129)	$ 53,096	$ 792,550	$ 1,534,143	$ 2,277,785	$ 2,305,066	$ 1,683,085	$ 1,356,447	$ 1,101,591	$ 885,270	
101	Net Costs - Revenues		$ 729,780	$ 729,927	$ 730,068	$ 738,310	$ 738,447	$ 738,487	$ 21,084	$ (627,374)	$ (330,749)	$ (258,180)	$ (219,008)	$ (1,100,907)	
102	Ending Balance before Interest		$ (1,398,469)	$ (673,317)	$ 53,938	$ 791,406	$ 1,530,996	$ 2,272,630	$ 2,298,868	$ 1,677,692	$ 1,352,336	$ 1,098,267	$ 882,583	$ (215,637)	
103	Average Balance		$ (1,763,359)	$ (1,038,281)	$ (311,095)	$ 422,251	$ 1,161,773	$ 1,903,386	$ 2,288,326	$ 1,991,379	$ 1,517,711	$ 1,227,357	$ 992,087	$ 334,816	
104	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%	
105	Interest Expense		$ (4,776)	$ (2,812)	$ (843)	$ 1,144	$ 3,146	$ 5,155	$ 6,198	$ 5,393	$ 4,110	$ 3,324	$ 2,687	$ 907	$ 23,634
106	Ending Balance Incl Interest Expense	$ (2,128,249)	$ (1,403,245)	$ (676,129)	$ 53,096	$ 792,550	$ 1,534,143	$ 2,277,785	$ 2,305,066	$ 1,683,085	$ 1,356,447	$ 1,101,591	$ 885,270	$ (214,730)	
107	**Total Over/Under Collection Ending Balance**		$ (1,476,644)	$ (749,125)	$ (19,496)	$ 720,371	$ 1,462,377	$ 2,206,434	$ 2,280,050	$ 1,705,193	$ 1,427,027	$ 1,220,064	$ 1,050,897	$ (3,794)	
108															$ -
109															
110	**Total Indirect Cost of Gas**	$ (2,202,050)	$ (4,374)	$ (2,409)	$ (438)	$ 1,556	$ 3,560	$ 5,570	$ 84,512	$ 84,495	$ 84,562	$ 83,196	$ 81,820	$ 78,195	$ (1,701,805)
111															
112	**Total Cost of Gas**	$ (2,202,050)	$ 725,406	$ 727,519	$ 729,630	$ 739,866	$ 742,007	$ 744,056	$ 3,139,731	$ 3,942,184	$ 5,424,428	$ 4,560,244	$ 3,505,757	$ 1,110,969	$ 23,889,747
113															
114	**Total Interest**	$ -	$ (4,975)	$ (3,010)	$ (1,039)	$ 948	$ 2,952	$ 4,961	$ 6,067	$ 5,389	$ 4,236	$ 3,580	$ 3,071	$ 1,416	$ 23,596

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2013**					
2						
3	Total		$	360,081		Company Analysis
4	Distribution		$	154,072		Company Analysis
5	Distribution (%)			42.79%		
6	Non-Distribution		$	206,009		Company Analysis
7	Non-Distribution(%)			57.21%		LN 6 / LN 3
8						
9	Non-Distribution		$	206,009		LN 6
10	Peak Period		$	189,524		Company Analysis
11	Peak Period (%)			92.00%		LN 10/ LN 9
12	Off-Peak Period		$	16,485		LN 9 - LN 10
13	Off-Peak Period (%)			8.00%		LN 12 / LN 9
14						
15	**Forecast Bad Debt Expense 12 Months Ended December 31, 2014**					
16						
17	Annual Total		$	500,000		Company Forecast
18	Annual Non-Distribution		$	286,059		LN 17* LN 7
19	Winter Non-Distribution		**$**	**263,169**		LN 18* LN 11
20	Summer Non-Distribution		$	22,890		LN 18* LN 13

Schedule 4

Reserved for Future Use

Schedules 5A & Attachments, 5B, 5C and 5D

Northern Utilities, Inc.
Estimated Gas Supply Demand Costs
November 1, 2013 through October 31, 2014

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,421,877	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 24,622,894	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	$ 1,725,894	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 1,658,750	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,956,197)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 27,510,064	Sum Lines 1 through 6.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2013 through October 31, 2014

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)	No	1,251	Centerville, NJ	Taunton, MA	$ 6.5734	12	Line 2 of Page 2, Att to Sch 5A	$ 8,223	$ 98,680
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.5166	9	Line 3 of Page 2, Att to Sch 5A	$ 351,660	$ 3,164,940
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.7419	3	Line 3 of Page 2, Att to Sch 5A	$ 374,190	$ 1,122,570
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
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.7640	12	Line 11 of Page 2, Att to Sch 5A	$ 5,562	$ 66,747
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 20.2343	12	Line 12 of Page 2, Att to Sch 5A	$ 687,966	$ 8,255,594
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 10.0219	12	Line 13 of Page 2, Att to Sch 5A	$ 59,500	$ 714,000
Union	M12205	M12	No	6,003	Dawn	Parkway	$ 2.4669	12	Line 14 of Page 2, Att to Sch 5A	$ 14,809	$ 177,706
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	Line 15 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 16 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 17 of Page 2, Att to Sch 5A	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	$ 0.4788	12	Line 18 of Page 2, Att to Sch 5A	$ 2,906	$ 34,876

Total Annual Demand Costs $ 34,770,665

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2013 through October 31, 2014

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	1,251			100%	0%	0%	$ 98,680	$ 98,680	$ -	$ -
Granite	10-010-FT-NN	100,000	24,217	35,529	40,254	24%	36%	40%	$ 3,164,940	$ 766,454	$ 1,124,472	$ 1,274,015
Granite	10-010-FT-NN	100,000	24,217	35,529	40,254	24%	36%	40%	$ 1,122,570	$ 271,853	$ 398,838	$ 451,879
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	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 66,747	$ 66,747	$ -	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 8,255,594	$ -	$ 8,255,594	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 714,000	$ 714,000	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 177,706	$ 177,706	$ -	$ -
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%	$ 34,876	$ 34,876	$ -	$ -
Annual Total Demand Costs									$ 34,770,665	$ 8,421,877	$ 24,622,894	$ 1,725,894

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2013 through October 31, 2014

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, FXW-10	$ 65,664	$ 78,411	$ 144,075
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	Line 2 of Page 3, FXW-10	$ 497	$ 687	$ 1,184
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.5480	12	Line 2 of Page 3, FXW-10	$ 189	$ 1,398	$ 1,587
W-10	01052	Storage	Yes	3,400,000		34,000			12	Line 3 of Page 3, FXW-10	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges	$ 3,036,846

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2013 through October 31, 2014

Resource	Contract Quantity	Maximum Daily Quantity	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Fixed Charges
LNG Supply	75,000	5,000	5	Att to Sch 5A, Page 4	[redacted]	[redacted]
Peaking Supply 1	225,000	15,000	5	Att to Sch 5A, Page 4	[redacted]	[redacted]
Peaking Supply 2	30,000	5,000	5	Att to Sch 5A, Page 4	[redacted]	[redacted]
Peaking Supply 3	250,000	25,000	5	Att to Sch 5A, Page 4	[redacted]	[redacted]
Total Peaking Supply Contract Demand Costs						$ 1,658,750

REDACTED

Northern Utilities, Inc.
Asset Management and Capacity Release Revenue Projections
November 1, 2013 through October 31, 2014

Asset Management Agreeement Revenue

Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	[redacted]
Algonquin Contract #93201A1C (1,251 Dth)	[redacted]
Wash 10 via Vector, TCPL, PNGTS	[redacted]
Tennessee Niagara	[redacted]
Tennessee Long-Haul	[redacted]
Total Asset Management	$ (11,805,500)

Capacity Release Revenue

Resources	Projected Revenue
Texas Eastern Contract 800384	$ (66,747)
Tennessee 5265	$ (83,950)
Total Capacity Release	$ (150,697)

Total Asset Management and Capacity Release Revenue	$ (11,956,197)

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for September 5, 2013

Estimated Adders to NYMEX Last Day Settlement

Line	Supply Source	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
1	Chicago	$0.189	$0.189	$0.189	$0.189	$0.189	$0.139	$0.139	$0.139	$0.139	$0.139	$0.139	$0.139
2	Iroquois Receipts	$1.902	$1.902	$1.902	$1.902	$1.902	$0.220	$0.220	$0.220	$0.220	$0.220	$0.220	$0.220
3	PNGTS Delivered	$4.250	$4.250	$4.250	$4.250	$4.250							
4	PNGTS Baseload	$3.000	$3.000	$3.000	$3.000	$3.000	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
5	Lewiston Baseload	$4.900	$4.900	$4.900	$4.900	$4.900	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
6	Niagara	$0.653	$0.653	$0.653	$0.653	$0.653	$0.350	$0.350	$0.350	$0.350	$0.350	$0.350	$0.350
7	Tennessee Production (Zone 0)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)
8	Tennessee Production (Zone L)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	Tennessee Production (Zone 4)	($0.020)	($0.020)	($0.020)	($0.020)	($0.020)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10	Tenessee Zone 4 Spot	($0.027)	($0.027)	($0.027)	($0.027)	($0.027)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	Peaking Supply 1	$22.940	$22.940	$22.940	$22.940	$22.940	NA	NA	NA	NA	NA	NA	NA
12	Peaking Supply 2	$30.558	$30.558	$30.558	$30.558	$30.558	NA	NA	NA	NA	NA	NA	NA
13	Peaking Supply 3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
14	LNG	$1.266	$4.515	$6.805	$5.883	$1.870	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
15	W10 Supply (Injection)	$0.189	$0.189	$0.189	$0.189	$0.189	$0.139	$0.139	$0.139	$0.139	$0.139	$0.139	$0.139
16	TGP FS Supply (Injection)	NA	NA	NA	NA	NA	($0.030)	($0.030)	($0.030)	($0.030)	($0.030)	($0.030)	($0.030)
17	W10 AMA Spot	$1.266	$4.515	$6.805	$5.883	$1.870	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
18	Tennessee Zone 6	$1.266	$4.515	$6.805	$5.883	$1.870	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
19	AGT Receipts	$0.239	$0.794	$0.836	$0.714	$0.263	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150
20													
21	NYMEX Forecast	$3.666	$3.830	$3.912	$3.912	$3.877	$3.809	$3.827	$3.855	$3.887	$3.904	$3.904	$3.928

Northern Utilities, Inc.
Transportation Contract Rates
November 2013 through October 2014

Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Demand Rate Support	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 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 5	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734
3	Granite	FT-NN	N/A	N/A		Page 7, 8	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.7419	$ 3.7419	$ 3.7419
4	Iroquois	RTS-1	Zone 1	Zone 1		Page 9	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 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	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456
6	PNGTS	FT (Seasonal)	N/A	N/A		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	$ 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	$ 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	$ 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	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396
11	Texas Eastern	FT-1/FTS	M3	M3	1	Pages 23, 24	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360
12	TransCanada	FT	Dawn	E. Hereford	2	Page 26	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343	$ 20.2343
13	TransCanada	FT	Parkway	Iroquois	2	Page 26	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219	$ 10.0219
14	Union	M12	Dawn	Parkway		Page 26	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669	$ 2.4669
15	Vector	FT-1	Alliance	Dawn		Page 36	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042
16	Vector	FT-1	W-10 Storage	Dawn		Page 37	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625							
17	Vector	FT-1	Alliance	St. Clair	3	Pages 33, 34	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745
18	Vector Canada	FT-1	St. Clair	Dawn		Page 26	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788	$ 0.4788

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Commodity Rate Support	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
19	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
20	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 5	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130
21	Granite	FT-NN	N/A	N/A		Page 7	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
22	Iroquois	RTS-1	Zone 1	Zone 1	4	Pages 9, 11	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048
23	LNG Trucking		Everett, MA	LNG Plant		Page 13	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700
24	PNGTS	FT	N/A	N/A		Page 17	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
25	Tennessee	FT-A	Zone 0	Zone 4	5	Page 20, 21	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055
26	Tennessee	FT-A	Zone 0	Zone 6	5	Page 20, 21	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532
27	Tennessee	FT-A	Zone L	Zone 4	5	Page 20, 21	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597
28	Tennessee	FT-A	Zone L	Zone 6	5	Page 20, 21	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078
29	Tennessee	FT-A	Zone 4	Zone 6	5	Page 20, 21	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188
30	Tennessee	FT-A	Zone 5	Zone 6	5	Page 20, 21	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896
31	TransCanada	FT	Dawn	E. Hereford		Page 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	TransCanada	FT	Parkway	Iroquois		Page 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Union	M12	Dawn	Parkway		Page 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Vector	FT-1	Alliance	W-10		Page 34	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
35	Vector	FT-1	Alliance	Dawn		Page 34	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Vector	FT-1	W-10 Storage	Dawn		Page 34	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018

Transportation Fuel Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Fuel Rate Support	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
37	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 6	0.92%	1.10%	1.10%	1.10%	1.10%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%
38	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 6	0.92%	1.10%	1.10%	1.10%	1.10%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%
39	Granite	FT-NN	N/A	N/A		Page 7	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
40	Iroquois	RTS-1	Zone 1	Zone 1	6	Page 12	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
41	PNGTS	FT	N/A	N/A	6	Page 18	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	Tennessee	FT-A	Zone 0	Zone 4		Page 21	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%
43	Tennessee	FT-A	Zone 0	Zone 6		Page 21	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%
44	Tennessee	FT-A	Zone L	Zone 4		Page 21	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%
45	Tennessee	FT-A	Zone L	Zone 6		Page 21	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
46	Tennessee	FT-A	Zone 4	Zone 6		Page 21	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%
47	Tennessee	FT-A	Zone 5	Zone 6		Page 21	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
48	TransCanada	FT	Dawn	E. Hereford	6	Page 38	1.49%	1.49%	1.49%	1.49%	1.49%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
49	TransCanada	FT	Parkway	Iroquois	6	Page 38	1.38%	1.38%	1.38%	1.38%	1.38%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%
50	Union	M12	Dawn	Parkway		Page 32	0.98%	0.98%	0.98%	0.98%	0.98%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
51	Vector	FT-1	Alliance	W-10	6	Page 39	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
52	Vector	FT-1	Alliance	Dawn	6	Page 39	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
53	Vector	FT-1	W-10 Storage	Dawn	6	Page 39	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%

Note 1	FT-1 Demand Rate = $4.876 plus FT-1 / FTS Rate = $0.66, totals to $5.536
Note 2	
Note 3	Negotiated Rate Agreement = $8.0908 per Dth, which is higher than max rate, so max rate prevails.
Note 4	RTS-1 Commodity Rate = $0.003 per Dth and ACA = $0.0018 per Dth. Total equals $0.0048
Note 5	Tennessee Variable Transportation Commodity Rates are calculated by adding the Maximum Commodity Rates found on Page 20 to the applicable EPCR found on page 21.
Note 6	Fuel Rates Estiamted based on 12 months historic averages.

Northern Utilities, Inc.
Underground Storage Contract Rates
November 2013 through October 2014

Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		Page 22	$ 0.0211	$ 1.5400	$ 0.0087	0.00%	$ 0.0087	1.45%
2	Texas Eastern	SS-1		Page 24	$ 0.1293	$ 5.3730				
3	W-10	Storage	1	Pages 40, 41, 42			$ -	0.40%	$ -	1.10%

Note 1 The demand charge for W-10 Storage shall be $240,833.34 per month.

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ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2012

•RATE SCHEDULE AFT-1

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(F-2/F-3)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(F-4)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(STB/SS-3)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(FTP)	$11.8368	$0.0018	$0.0018	$0.3910	$0.0018	$0.3892
(PSS-T)	$ 9.7854	$0.0018	$0.0018	$0.3235	$0.0018	$0.3217
(AFT-2)	$ 6.1138	$0.0018	$0.0018	$0.2028	$0.0018	$0.2010
(AFT-3)	$10.7554	$0.0018	$0.0018	$0.3554	$0.0018	$0.3536
(AFT-5)	$12.6265	$0.0018	$0.0018	$0.4169	$0.0018	$0.4151
(ITP)	$13.0110	$0.0018	$0.0018	$0.4296	$0.0018	$0.4278
(X-35)	$10.2027	$0.0018	$0.0018	$0.3372	$0.0018	$0.3354
X-39	$13.2089	$0.0018	$0.0018	$0.4361	$0.0018	$0.4343
Incremental Surcharges						
Hubline	**$ 1.8607**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0612**
Secondary 1/		**$0.0612**	**$0.0000**			
Tiverton	**$ 1.6424**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0540**
Ramapo	**$ 7.5608**	**$0.0000**	**$0.0000**	**$0.2486**	**$0.0000**	**$0.2486**

•RATE SCHEDULE AFT-1S

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	**$ 2.6294**	**$0.2291**	**$0.0130**	**$0.2291**	**$0.0130**	**$0.0864**
(F-2/F-3)	**$ 2.6294**	**$0.2291**	**$0.0130**	**$0.2291**	**$0.0130**	**$0.0864**
(F-4)	**$ 2.6294**	**$0.2291**	**$0.0130**	**$0.2291**	**$0.0030**	**$0.0864**
(STB/SS-3)	**$ 2.6294**	**$0.2291**	**$0.0130**	**$0.2291**	**$0.0130**	**$0.0864**
(Hubline) 1/		**$0.0612**	**$0.0000**			

•OTHER FIRM RATE SCHEDULES

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
AFT-E	**$ 6.5734**	**$0.0130**	**$0.0130**	**$0.2291**	**$0.0130**	**$0.2161**
(Hubline) 1/		**$0.0612**	**$0.0000**			
AFT-ES	**$ 2.6294**	**$0.2291**	**$0.0130**	**$0.2291**	**$0.0130**	**$0.0864**
(Hubline) 1/		**$0.0612**	**$0.0000**			
T-1	**$ 1.6480**	**$0.0057**		**$0.0599**		
AFT-4	**$ 3.5211**	**$0.0031**		**$0.1189**		
AFT-CL:						
Canal	**$ 2.0858**	**$0.0018**	**$0.0018**	**$0.0704**	**$0.0018**	**$0.0686**
Middletown	**$ 3.2764**	**$0.0018**	**$0.0018**	**$0.1095**	**$0.0018**	**$0.1077**
Cleary	**$ 1.4529**	**$0.0018**	**$0.0018**	**$0.0496**	**$0.0018**	**$0.0478**
Lake Road	**$ 0.6476**	**$0.0018**	**$0.0018**	**$0.0231**	**$0.0018**	**$0.0213**
Brayton Pt.	**$ 1.2700**	**$0.0018**	**$0.0018**	**$0.0436**	**$0.0018**	**$0.0418**
Manchester	**$ 2.4500**	**$0.0018**	**$0.0018**	**$0.0823**	**$0.0018**	**$0.0805**
Bellingham	**$ 0.9714**	**$0.0018**	**$0.0018**	**$0.0337**	**$0.0018**	**$0.0319**
Phelps Dodge	**$ 0.0000**	**$0.0184**	**$0.0018**	**$0.0184**	**$0.0018**	**$0.0000**
Cape Cod	**$ 9.0501**	**$0.0018**	**$0.0018**	**$0.2993**	**$0.0018**	**$0.2975**
Northeast Gateway	**$ 4.3449**	**$0.0018**	**$0.0018**	**$0.1446**	**$0.0018**	**$0.1428**
J-2 Facility	**$ 4.6346**	**$0.0018**	**$0.0018**	**$0.1542**	**$0.0018**	**$0.1524**
Kleen Energy	**$ 1.2247**	**$0.0018**	**$0.0018**	**$0.0421**	**$0.0018**	**$0.0403**
X-33	**$ 3.0873**	**$0.0412**		**$0.1427**		

•INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun	
	Max	Min	Max	Min
AIT-1	**$0.2439**	**$0.0094**	**$0.2439**	**$0.0094**
(Hubline 1/)	**$0.0612**	**$0.0000**		
AIT-2				
Brayton Pt.	**$0.0436**	**$0.0018**	**$0.0436**	**$0.0018**
Manchester	**$0.0823**	**$0.0018**	**$0.0823**	**$0.0018**
Canal	**$0.0704**	**$0.0018**	**$0.0704**	**$0.0018**
Cape Cod	**$0.2993**	**$0.0018**	**$0.2993**	**$0.0018**
Northeast Gateway	**$0.1446**	**$0.0018**	**$0.1446**	**$0.0018**
J-2 Facility	**$0.1542**	**$0.0018**	**$0.1542**	**$0.0018**
Kleen Energy	**$0.0421**	**$0.0018**	**$0.0421**	**$0.0018**
PAL	**$0.2439**	**$0.0000**	**$0.0000**	**$0.0000**

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	**$5.3900**	**$0.0000**

Rates are per MMBTU. Commodity rates include ACA Charge of $0.0018.

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
System Services		
Winter	Dec 1 - Mar 31	1.10%
Spring, Summer and Fall	Apr 1 - Nov 30	0.92%
Incremental Ramapo Services		
Winter	Dec 1 - Mar 31	1.90%
Spring, Summer and Fall	Apr 1 - Nov 30	1.87%

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

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

4.2 Rate Schedule FT-NN
No-Notice Firm Transportation Service
Currently Effective Rates

	$/Dth		
	Base Tariff Rate	ACA Adj.	Total Current Rate
Reservation Charge:			
Maximum	$3.2913		$3.2913
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0018	$0.0018
Minimum	$0.0000	$0.0018	$0.0018
Authorized Overrun Commodity Charge:			
Maximum	$0.1082	$0.0018	$0.1100
Minimum	$0.0000	$0.0018	$0.0018
Fuel and Losses			
Percentage			0.35%
Volumetric Reservation Charge			
Maximum	$0.1082	$0.0018	$0.1100
Minimum	$0.0000	$0.0018	$0.0018

Projected Granite Reservation Charge 8/1/2013

Line	Description		Value	Reference
1	Projected Big Three Incremental Cost of Service 8/1/2013	$	617,150	RP12-838, Sch. 1, L8
2	Total Billing Determinants		1,613,324	RP12-838, Sch. 1, L9
3	Projected Big Three Incremental Reservation Charge	$	0.3825	Line 1 divided by Line 2
4	Granite Reservation Charge 8/1/2012	$	3.1000	FT Base Rate (RP10-896)
5	Projected Granite Reservation Charge 8/1/2013	$	3.4825	Line 3 plus Line 4

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

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

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

(Footnotes continued on Sheet 4.01)

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

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

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

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

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:	
Commodity	0.0018

MEASUREMENT VARIANCE/FUEL USE FACTOR:	
Minimum	0.00%
Maximum (Non-Eastchester Shipper)	1.00%
Maximum (Eastchester Shipper)	4.50%
Maximum (Brookfield Shipper)	1.20%

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Average
Iroquois	Zone 1	Zone 1	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.20%	0.20%	0.40%		0.60%	0.50%	0.20%

REDACTED

Line	Item	Value	Reference
1	LNG Trucking Rate	[redacted]	Page 14
2	Diesel Adjustment	[redacted]	
3	Current Diesel Rate per Gallon	[redacted]	Page 16
4	Forecast Diesel Rate per Gallon	[redacted]	Estimate
5	Diesel Fuel Adjustment per Dth	[redacted]	Page 15
6		[redacted]	
7	Average LNG Trucking Cost	$ 1.17	Line 1 plus Line 7

CONFIDENTIAL INFORMATION

REDACTED

LNG TRANSPORTATION RATE AGREEMENT

DATE: October 24, 2012

CONFIDENTIAL

CARRIER:

[redacted]

CONFIDENTIAL INFORMATION

SHIPPER:

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

EFFECTIVE DATE: 11/01/12

EXPIRATION DATE: 10/31/13

ORIGIN	**DESTINATION**	**COMMODITY DATE**	**RATE**
Everett, MA	Lewiston, ME	11/01/12 to 10/31/13	[redacted]

CONFIDENTIAL INFORMATION

OTHER TERMS AND CONDITIONS:

CONFIDENTIAL INFORMATION

[redacted]

CONFIDENTIAL INFORMATION

[redacted]

SHIPPER: **Northern Utilities Inc.**

By: ______________________

Robert Furino

Its: **Director of Energy Contracts**

K:\Unitil 2012-13\Northern Utilities-LNG Trnsptn Rate Agrmnt 12-13

REDACTED

[redacted]

Exhibit 1

CONFIDENTIAL
INFORMATION

Table No. 1
Weekly Diesel Fuel Surcharge

CONFIDENTIAL
INFORMATION

If the Price is: (See Note 1)		The Weekly Fuel Surcharge Will Be:	If the Price is: (See Note 1)		The Weekly Fuel Surcharge Will Be:
At Least: ($/gallon)	But Less Than: ($/gallon)		At Least: ($/gallon)	But Less Than: ($/gallon)	

[redacted]

Effective April 1, 2012

These Standard Terms and Conditions Contain Privileged and Confidential Information

K:/Standard Terms and Conditions – April 1, 2012

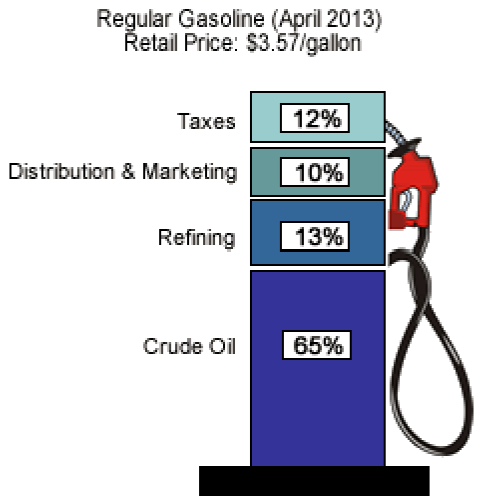
CONFIDENTIAL INFORMATION

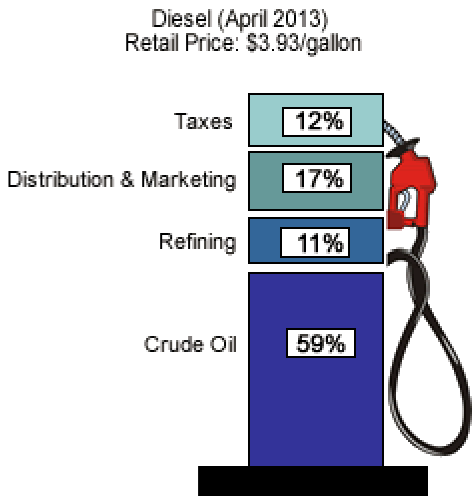
U.S. On-Highway Diesel Fuel Prices* (dollars per gallon)full history

				Change from	
	05/27/13	**06/03/13**	**06/10/13**	**week ago**	**year ago**
U.S.	3.880	3.869	3.849	↓ -0.020	↑ 0.068
East Coast (PADD1)	3.864	3.855	3.839	↓ -0.016	↑ 0.021
New England (PADD1A)	3.991	3.984	3.978	↓ -0.006	↑ 0.004
Central Atlantic (PADD1B)	3.928	3.920	3.907	↓ -0.013	↓ -0.002
Lower Atlantic (PADD1C)	3.792	3.783	3.762	↓ -0.021	↑ 0.041
Midwest (PADD2)	3.916	3.900	3.877	↓ -0.023	↑ 0.181
Gulf Coast (PADD3)	3.775	3.770	3.748	↓ -0.022	↑ 0.050
Rocky Mountain (PADD4)	3.863	3.866	3.865	↓ -0.001	↓ -0.008
West Coast (PADD5)	3.986	3.968	3.945	↓ -0.023	↓ -0.046
West Coast less California	3.917	3.899	3.870	↓ -0.029	↓ -0.032
California	4.044	4.025	4.008	↓ -0.017	↓ -0.058

**prices include all taxes*

What we pay for in a gallon of:


Regular Gasoline (April 2013)
Retail Price: $3.57/gallon


Diesel (April 2013)
Retail Price: $3.93/gallon

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$40.2456	---------	$40.2456
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$76.4666	---------	$76.4666
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0018	$00.0018
	-- Minimum	$00.0000	$00.0018	$00.0018
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$27.0128	---------	$27.0128
	--Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.4350	$00.0018	$00.4369
	--Minimum	$00.0000	$00.0018	$00.0018

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Average
PNGTS	N/A	N/A	0.00%	0.00%	0.00%	-0.30%	-0.50%	-0.50%	-0.20%	-0.20%	-0.30%	-0.50%	-0.50%	-0.50%	-0.29%

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

Daily Base Reservation Rate 1/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.1891		$0.3986	$0.5372	$0.5468	$0.6033	$0.6406	$0.8040
L		$0.1675						
1	$0.2862		$0.2742	$0.3660	$0.5198	$0.5137	$0.5798	$0.7131
2	$0.5372		$0.3638	$0.1877	$0.1752	$0.2258	$0.3119	$0.4030
3	$0.5468		$0.2875	$0.1892	$0.1356	$0.2107	$0.3838	$0.4434
4	$0.6951		$0.6406	$0.2421	$0.3696	$0.1798	$0.1948	$0.2791
5	$0.8294		$0.5819	$0.2541	$0.3082	$0.2002	$0.1875	$0.2446
6	$0.9595		$0.6683	$0.4588	$0.5058	$0.3573	$0.1861	$0.1606

Maximum Reservation Rates 2 /, 3 /

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

Notes:
1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2751	$0.2625	$0.3124
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2339	$0.2385	$0.2723
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0757	$0.1214	$0.1345
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.1012	$0.1400	$0.1528
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0468	$0.0662	$0.1073
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0659	$0.0653	$0.0811
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.1014	$0.0549	$0.0334

Minimum
Commodity Rates 1/, 2/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0050		$0.0133	$0.0195	$0.0237	$0.0268	$0.0302	$0.0364
L		$0.0030						
1	$0.0060		$0.0099	$0.0165	$0.0197	$0.0228	$0.0274	$0.0318
2	$0.0185		$0.0105	$0.0030	$0.0046	$0.0074	$0.0118	$0.0161
3	$0.0225		$0.0187	$0.0044	$0.0020	$0.0099	$0.0136	$0.0181
4	$0.0268		$0.0223	$0.0105	$0.0123	$0.0046	$0.0064	$0.0110
5	$0.0302		$0.0274	$0.0118	$0.0136	$0.0064	$0.0064	$0.0084
6	$0.0364		$0.0318	$0.0161	$0.0181	$0.0104	$0.0059	$0.0038

Maximum
Commodity Rates 1/, 2/, 3/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0050		$0.0133	$0.0195	$0.0237	$0.2769	$0.2643	$0.3142
L		$0.0030						
1	$0.0060		$0.0099	$0.0165	$0.0197	$0.2357	$0.2403	$0.2741
2	$0.0185		$0.0105	$0.0030	$0.0046	$0.0775	$0.1232	$0.1363
3	$0.0225		$0.0187	$0.0044	$0.0020	$0.1030	$0.1418	$0.1546
4	$0.0268		$0.0223	$0.0105	$0.0123	$0.0486	$0.0680	$0.1091
5	$0.0302		$0.0274	$0.0118	$0.0136	$0.0677	$0.0671	$0.0829
6	$0.0364		$0.0318	$0.0161	$0.0181	$0.1032	$0.0567	$0.0352

Notes:

1/ Includes a per Dth charge for (ACA) Annual Charge Adjustment of $0.0018

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.

3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

FUEL AND EPCR

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

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	0.67%		1.67%	2.40%	2.89%	3.41%	3.82%	4.49%
L		0.43%						
1	0.79%		1.27%	2.05%	2.42%	2.92%	3.49%	3.95%
2	2.44%		1.34%	0.42%	0.62%	1.00%	1.56%	2.02%
3	2.96%		2.47%	0.62%	0.31%	1.31%	1.79%	2.32%
4	3.51%		2.73%	1.33%	1.55%	0.64%	0.88%	1.38%
5	3.95%		3.49%	1.56%	1.81%	0.88%	0.87%	1.06%
6	4.68%		4.08%	2.05%	2.32%	1.31%	0.73%	0.46%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	$0.0032		$0.0123	$0.0190	$0.0237	$0.0286	$0.0325	$0.0390
L		$0.0011						
1	$0.0043		$0.0086	$0.0158	$0.0193	$0.0240	$0.0293	$0.0337
2	$0.0190		$0.0093	$0.0010	$0.0028	$0.0062	$0.0113	$0.0155
3	$0.0237		$0.0193	$0.0028	$0.0000	$0.0091	$0.0134	$0.0179
4	$0.0286		$0.0221	$0.0092	$0.0112	$0.0029	$0.0051	$0.0097
5	$0.0325		$0.0293	$0.0113	$0.0134	$0.0051	$0.0050	$0.0067
6	$0.0390		$0.0337	$0.0155	$0.0179	$0.0090	$0.0038	$0.0014

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.21%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.8100	$2.8100 1/		
Space Rate	$0.0286	$0.0286 1/		
Injection Rate	$0.0073	$0.0073	1.45%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.3372	$0.3372 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.5400	$1.5400 1/		
Space Rate	$0.0211	$0.0211 1/		
Injection Rate	$0.0087	$0.0087	1.45%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1848	$0.1848 1/		

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.06%.

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

CURRENTLY EFFECTIVE RATES 2/01/2013

•RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.8030	6.5800	2.7210
WLA-AAB	2.8240	2.6010	1.1300
ELA-AAB	2.3740	2.1510	0.9500
ETX-AAB	2.1880	1.9650	0.8750
STX-STX	5.7340	5.5110	2.2920
STX-WLA	5.8930	5.6700	2.3550
STX-ELA	6.8110	6.5880	2.7220
STX-ETX	6.8100	6.5870	2.7210
WLA-WLA	2.0570	1.8340	0.8220
WLA-ELA	2.8300	2.6070	1.1300
WLA-ETX	2.8310	2.6080	1.1300
ELA-ELA	2.3780	2.1550	0.9500
ETX-ETX	2.1920	1.9690	0.8750
ETX-ELA	2.3790	2.1560	0.9500
M1-M1	4.3950	4.1720	1.7550
M1-M2	7.9740	7.7510	3.1850
M1-M3	10.4160	10.1930	4.1610
M2-M2	6.2350	6.0120	2.4900
M2-M3	8.8160	8.5930	3.5220
M3-M3	5.0990	4.8760	2.0360

7(C) RATE SCHEDULES	
FTS	5.3510
FTS-2	7.9590
FTS-4	7.7330
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0100

SCT DEMAND CHARGES	
Access Area	0.0020
M1-M1	0.0040
M1-M2	0.0050
M1-M3	0.0060

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	**STX**	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	0.0103	0.0112	0.0170	0.0169	0.0341	0.0563	0.0717
from WLA	0.0112	0.0073	0.0123	0.0124	0.0295	0.0517	0.0671
from ELA	0.0170	0.0123	0.0111	0.0112	0.0283	0.0505	0.0659
from ETX	0.0169	0.0124	0.0112	0.0111	0.0283	0.0505	0.0659
from M1	0.0341	0.0295	0.0283	0.0283	0.0172	0.0394	0.0548
from M2	0.0563	0.0517	0.0505	0.0505	0.0394	0.0286	0.0440
from M3	0.0717	0.0671	0.0659	0.0659	0.0548	0.0440	0.0216

Backhaul	**STX**	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	0.0103						
from WLA	0.0112	0.0073					
from ELA	0.0170	0.0123	0.0111				
from ETX	0.0169	0.0124	0.0112	0.0111			
from M1	0.0310	0.0264	0.0252	0.0252	0.0141		
from M2	0.0513	0.0467	0.0455	0.0455	0.0344	0.0245	
from M3	0.0653	0.0607	0.0595	0.0595	0.0484	0.0385	0.0181

SCT USAGE-1

Forward Haul	**STX**	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	0.1914	0.1974	0.2334	0.2332	0.3873	0.5271	0.6227
from WLA	0.1974	0.0675	0.0978	0.0980	0.2519	0.3916	0.4873
from ELA	0.2334	0.0978	0.0818	0.0820	0.2359	0.3757	0.4713
from ETX	0.2332	0.0980	0.0820	0.0757	0.2298	0.3695	0.4652
from M1	0.3873	0.2519	0.2359	0.2298	0.1541	0.2938	0.3895
from M2	0.5271	0.3916	0.3757	0.3695	0.2938	0.2260	0.3261
from M3	0.6227	0.4873	0.4713	0.4652	0.3895	0.3261	0.1816

Backhaul	**STX**	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	0.1914						
from WLA	0.1974	0.0675					
from ELA	0.2334	0.0978	0.0818				
from ETX	0.2332	0.0980	0.0820	0.0757			
from M1	0.3842	0.2488	0.2328	0.2267	0.1510		
from M2	0.5221	0.3866	0.3707	0.3645	0.2888	0.2219	
from M3	0.6163	0.4809	0.4649	0.4588	0.3831	0.3206	0.1781

IT-1 USAGE-1

Forward Haul	**STX**	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**

from STX	0.1914	0.1976	0.2336	0.2334	0.3878	0.5276	0.6234
from WLA	0.1976	0.0676	0.0981	0.0982	0.2524	0.3922	0.4880
from ELA	0.2336	0.0981	0.0820	0.0821	0.2364	0.3762	0.4720
from ETX	0.2334	0.0982	0.0821	0.0758	0.2302	0.3700	0.4658
from M1	0.3878	0.2524	0.2364	0.2302	0.1544	0.2942	0.3900
from M2	0.5276	0.3922	0.3762	0.3700	0.2942	0.2263	0.3265
from M3	0.6234	0.4880	0.4720	0.4658	0.3900	0.3265	0.1820

Backhaul	**STX**	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	0.1914						
from WLA	0.1976	0.0676					
from ELA	0.2336	0.0981	0.0820				
from ETX	0.2334	0.0982	0.0821	0.0758			
from M1	0.3847	0.2493	0.2333	0.2271	0.1513		
from M2	0.5226	0.3872	0.3712	0.3650	0.2892	0.2222	
from M3	0.6170	0.4816	0.4656	0.4594	0.3836	0.3210	0.1785

•OTHER TRANSPORTATION SERVICES

	Reservation	**Usage-1**	**Shrinkage**	
			In Path	Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3410 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	0.6600		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	5.5500		0.40%	
FT-1/NC	6.5600		0.00%	
FT-1/RIV	10.4390		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	0.6040 2/		0.00%	
FT-1/TME	10.5510		3.27%	5.21%
FT-1/TME2	19.9110		2.44%	3.64%
FT-1/TME3	21.7860	-0.0099	1.59%	
FT-1/MX	3.1240		0.27%	
FT-1/TME12	17.4990		1.93%	
FT-1/PEP	8.3910		0.02%	
MLS-1/FH	0.6190		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270	0.0305 3/	0.01%	
MLS-1/HS	6.1130	0.2010 3/	0.01%	

			Primary Rec Pt	Secondary Rec Pt
FT-1/TMX	18.9590	-0.0001	1.15%	Winter 3.91%/Summer 3.48%

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

•STORAGE SERVICES

	RES.	**SPACE**	**INJ.**	**WITH.**
SS	5.2760	0.1293	0.0357	0.0550
SS-1	5.3730	0.1293	0.0357	0.0549
X-28	4.6780	0.1293	0.0357	0.0507
FSS-1	0.8950	0.1293	0.0357	0.0357
ISS-1		0.0323	0.1914	0.0357

•SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31 FOR TRANSPORTATION SERVICE

	STX	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	1.27%	1.29%	1.70%	1.70%	3.92%	5.34%	6.28%
from WLA	1.29%	1.23%	1.77%	1.77%	3.99%	5.41%	6.35%
from ELA	1.70%	1.77%	1.77%	1.77%	3.99%	5.41%	6.35%
from ETX	1.70%	1.77%	1.77%	1.60%	3.82%	5.24%	6.18%
from M1	3.92%	3.99%	3.99%	3.82%	2.22%	3.64%	4.58%
from M2	5.34%	5.41%	5.41%	5.24%	3.64%	2.95%	3.91%
from M3	6.28%	6.35%	6.35%	6.18%	4.58%	3.91%	2.50%

December 1 through March 31 FOR TRANSPORTATION SERVICE WITH PARTIAL BACKHAUL PATHS

	STX	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	1.27%						
from WLA	1.29%	1.23%					
from ELA	1.70%	1.77%	1.77%				
from ETX	1.70%	1.77%	1.60%	1.60%			
from M1	1.70%	1.77%	1.77%	1.60%	0.00%		
from M2	1.70%	1.77%	1.77%	1.60%	0.00%	0.00%	

from M3	1.70%	1.77%	1.77%	1.60%	0.00%	0.00%	0.00%

April 1 through November 30 FOR TRANSPORTATION SERVICE

	STX	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	1.07%	1.08%	1.38%	1.38%	3.48%	4.64%	5.41%
from WLA	1.08%	1.42%	1.56%	1.56%	3.66%	4.82%	5.59%
from ELA	1.38%	1.56%	1.56%	1.56%	3.66%	4.82%	5.59%
from ETX	1.38%	1.56%	1.56%	1.42%	3.52%	4.68%	5.45%
from M1	3.48%	3.66%	3.66%	3.52%	2.10%	3.26%	4.03%
from M2	4.64%	4.82%	4.82%	4.68%	3.26%	2.70%	3.48%
from M3	5.41%	5.59%	5.59%	5.45%	4.03%	3.48%	2.33%

April 1 through November 30 FOR TRANSPORTATION SERVICE WITH PARTIAL BACKHAUL PATHS

	STX	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	1.07%						
from WLA	1.08%	1.42%					
from ELA	1.38%	1.56%	1.56%				
from ETX	1.38%	1.56%	1.42%	1.42%			
from M1	1.38%	1.56%	1.56%	1.42%	0.00%		
from M2	1.38%	1.56%	1.56%	1.42%	0.00%	0.00%	
from M3	1.38%	1.56%	1.56%	1.42%	0.00%	0.00%	0.00%

NON-ASA RATE SCHEDULES

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

ASA STORAGE RATE SCHEDULES

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	3.20%	3.06
FSS-1,ISS-1	0.86%	0.86%
INJECTIONS	0.86%	0.86%
INVENTORY LEVEL	0.07%	0.07%

- **SURCHARGES**

ACA Surcharge
Commodity 0.0018

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

Canadian Fixed Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Demand Toll	$CAD / GJ	$ 9.24034	Page 30
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.43662	Page 28
4	Total Demand Toll	$CAD / GJ	$ 9.67696	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.9816	Page 27
6	Total Demand Toll	$US / GJ	$ 9.4989	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Total Demand Toll	$US / Dth	$ 10.0219	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Demand Toll	$CAD / GJ	$ 18.96846	Page 29
12	Union Dawn Surcharge	$CAD / GJ	$ 0.13281	Page 28
13	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.43662	Page 28
14	Total Demand Toll	$CAD / GJ	$ 19.53789	Sum Lines Above.
15	$CAD to $US	Ratio	0.9816	Page 27
16	Total Demand Toll	$US / GJ	$ 19.1784	Line 13 times Line 14
17	GJ per Dth	Ratio	1.0551	
18	Total Demand Toll	$US / Dth	$ 20.2343	Line 15 divided by Line 16
19				
20	Dawn to Parkway on Union Pipeline			
21	Total Demand Toll	$CAD / GJ	$ 2.3820	Page 31
22	$CAD to $US	Ratio	0.9816	Page 27
23	Total Demand Toll	$US / GJ	$ 2.3382	Line 13 times Line 14
24	GJ per Dth	Ratio	1.0551	
25	Total Demand Toll	$US / Dth	$ 2.4669	Line 15 divided by Line 16
26				
27	St. Clair to Dawn on Vector Canada			
28	Total Demand Toll	$CAD / GJ	$ 0.4623	Page 35
29	$CAD to $US	Ratio	0.9816	Page 27
30	Total Demand Toll	$US / GJ	$ 0.4538	Line 13 times Line 14
31	GJ per Dth	Ratio	1.0551	
32	Total Demand Toll	$US / Dth	$ 0.4788	Line 15 divided by Line 16

Canadian Variable Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Variable Toll	$CAD / GJ	$ -	Page 30
3	Delivery Pressure Commodity Toll	$CAD / GJ	$ -	Page 28
4	Variable Transportation Rate	$CAD / GJ	$ -	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.9816	Page 27
6	Variable Transportation Rate	$US / GJ	$ -	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ -	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Commodity Rate	$CAD / GJ	$ -	Page 29
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ -	Page 28
13	Variable Transportation Rate	$CAD / GJ	$ -	Line 11 plus Line 12
14	$CAD to $US	Ratio	0.9816	Page 27
15	Variable Transportation Rate	$US / GJ	$ -	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ -	Line 15 divided by Line 16

Daily currency converter

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

Currency Converter

Amount: 1.00 cash rate: ☐

From: Canadian Dollar To: U.S. dollar

Convert

Answer: 0.98 Exchange Rate: 0.9816 Summary: On 10 June 2013, 1.00 Canadian Dollar(s) = 0.98 U.S. dollar(s), at an exchange rate of 0.9816 (using nominal rate).

See Also

10-year currency converter

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

The Bank currently collects data for about 55 foreign currencies. This data is intended primarily for people with a research interest in foreign exchange markets, and represents a sampling of currencies from various regions. It is not meant to be an exhaustive listing of all world currencies.

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

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

Transportation Tolls
Mainline 2013 - 2017 Tolls effective July 1, 2013

System Average Unit Cost of Transportation

Line No.	Particulars	Daily Allocation Base		Adjusted Annual Unit Cost		Adjusted Daily Unit Cost	
	(a)	(b)		(c)		(d)	
1	Energy	4,842,625	GJ	31.2032718304	$/GJ	0.0854884160	$/GJ
2	Energy Distance	4,218,985,129	GJ-KM	0.1866454820	$/GJ-Km	0.0005113575	$/GJ-Km

Storage Transportation Service

Line No.	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
3	Centram MDA	4.82275	0.15856
4	Union WDA	25.55020	0.84001
5	Union NDA	10.88920	0.35800
6	Union EDA	7.61793	0.25045
7	KPUC EDA	7.32723	0.24090
8	GMIT EDA	12.52810	0.41188
9	Enbridge CDA	3.78609	0.12447
10	Enbridge EDA	9.75548	0.32073
11	Cornwall	9.89920	0.32545
12	Philipsburg	12.56045	0.41295

Firm Transportation - Short Notice

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent FT-SN for ST-SN ($/GJ)
	(a)	(b)	(c)
13	Kirkwall to Thorold CDA	4.49081	0.14764
14	Union Parkway Belt to Goreway CDA	3.34364	0.10992
15	Union Parkway Belt to Victoria Square #2 CDA	3.94878	0.12982
16	Union Parkway Belt to Schomberg #2 CDA	3.90927	0.12852

Note: Bid floors for ST-SN may be set at the daily equivalent FT-SN toll or higher.

Delivery Pressure

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)	Fuel Ratio (%)
	(a)	(b)	(c)	(d)
17	Average Delivery Pressure Toll	0.43662	0.01435	0.19%

Note: Delivery Pressure toll applies to the following locations: Emerson 1, Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford
The Daily equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

Union Dawn Receipt Point Surcharge

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)	Fuel Ratio (%)
	(a)	(b)	(c)	(d)
18	Union Dawn Receipt Point Surcharge	0.13281	0.00437	0.00%

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/MO)	Daily Equivalent FT for IT / STFT ($/GJ)
1	Union Dawn	Nipigon WDA	26.12009	0.8587
2	Union Dawn	Union NDA	14.41835	0.4740
3	Union Dawn	Calstock NDA	20.97568	0.6896
4	Union Dawn	Tunis NDA	16.92547	0.5565
5	Union Dawn	GMIT NDA	13.91581	0.4575
6	Union Dawn	Union SSMDA	12.06507	0.3967
7	Union Dawn	Union NCDA	8.99195	0.2956
8	Union Dawn	Union CDA	6.21000	0.2042
9	Union Dawn	Enbridge CDA	7.16453	0.2356
10	Union Dawn	Union EDA	11.14630	0.3665
11	Union Dawn	Enbridge EDA	13.28433	0.4367
12	Union Dawn	GMIT EDA	16.05695	0.5279
13	Union Dawn	KPUC EDA	10.85607	0.3569
14	Union Dawn	North Bay Junction	11.72039	0.3853
15	Union Dawn	Kirkwall	5.53481	0.1820
16	Union Dawn	Enbridge SWDA	2.60027	0.0855
17	Union Dawn	Union SWDA	2.65611	0.0873
18	Union Dawn	Spruce	29.53850	0.9711
19	Union Dawn	Emerson 1	27.33127	0.8986
20	Union Dawn	Emerson 2	27.33127	0.8986
21	Union Dawn	St. Clair	2.97092	0.0977
22	Union Dawn	Dawn Export	2.60027	0.0855
23	Union Dawn	Niagara Falls	7.26719	0.2389
24	Union Dawn	Chippawa	7.30436	0.2401
25	Union Dawn	Iroquois	12.76919	0.4198
26	Union Dawn	Cornwall	13.42804	0.4415
27	Union Dawn	Napierville	15.81773	0.5200
28	Union Dawn	Philipsburg	16.08930	0.5290
29	Union Dawn	East Hereford	18.96846	0.6236
30	Union Dawn	Welwyn	33.73554	1.1091
31	Union EDA	Empress	-	1.6504
32	Union EDA	TransGas SSDA	-	1.4286
33	Union EDA	Centram SSDA	-	1.3377
34	Union EDA	Centram MDA	-	1.2003
35	Union EDA	Centrat MDA	-	1.1398
36	Union EDA	Union WDA	-	0.9028
37	Union EDA	Nipigon WDA	-	0.8055
38	Union EDA	Union NDA	-	0.4208
39	Union EDA	Calstock NDA	-	0.6364
40	Union EDA	Tunis NDA	-	0.5032
41	Union EDA	GMIT NDA	-	0.4043
42	Union EDA	Union SSMDA	-	0.6776
43	Union EDA	Union NCDA	-	0.2948
44	Union EDA	Union CDA	-	0.2658
45	Union EDA	Enbridge CDA	-	0.2365
46	Union EDA	Union EDA	-	0.0855
47	Union EDA	Enbridge EDA	-	0.1758
48	Union EDA	GMIT EDA	-	0.2475
49	Union EDA	KPUC EDA	-	0.1268
50	Union EDA	North Bay Junction	-	0.3321
51	Union EDA	Kirkwall	-	0.2700
52	Union EDA	Enbridge SWDA	-	0.3665
53	Union EDA	Union SWDA	-	0.3683
54	Union EDA	Spruce	-	1.1398
55	Union EDA	Emerson 1	-	1.1646
56	Union EDA	Emerson 2	-	1.1646
57	Union EDA	St. Clair	-	0.3786
58	Union EDA	Dawn Export	-	0.3665
59	Union EDA	Niagara Falls	-	0.3183
60	Union EDA	Chippawa	-	0.3195
61	Union EDA	Iroquois	-	0.1430
62	Union EDA	Cornwall	-	0.1614
63	Union EDA	Napierville	-	0.2399
64	Union EDA	Philipsburg	-	0.2489
65	Union EDA	East Hereford	-	0.3435
66	Union EDA	Welwyn	-	1.3377
67	Union NCDA	Empress	-	1.4953
68	Union NCDA	TransGas SSDA	-	1.2735
69	Union NCDA	Centram SSDA	-	1.1826
70	Union NCDA	Centram MDA	-	1.0459
71	Union NCDA	Centrat MDA	-	0.9828
72	Union NCDA	Union WDA	-	0.7459
73	Union NCDA	Nipigon WDA	-	0.6486

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/MO)	Daily Equivalent FT for IT / STFT ($/GJ)
1	Union Parkway Belt	Calstock NDA	17.44683	0.5736
2	Union Parkway Belt	Tunis NDA	13.39663	0.4404
3	Union Parkway Belt	GMIT NDA	10.38681	0.3415
4	Union Parkway Belt	Union SSMDA	15.59391	0.5127
5	Union Parkway Belt	Union NCDA	5.46310	0.1796
6	Union Parkway Belt	Union CDA	3.06658	0.1008
7	Union Parkway Belt	Enbridge CDA	3.78609	0.1245
8	Union Parkway Belt	Union EDA	7.61793	0.2505
9	Union Parkway Belt	Enbridge EDA	9.75548	0.3207
10	Union Parkway Belt	GMIT EDA	12.52810	0.4119
11	Union Parkway Belt	KPUC EDA	7.32723	0.2409
12	Union Parkway Belt	North Bay Junction	8.19155	0.2693
13	Union Parkway Belt	Kirkwall	3.19458	0.1050
14	Union Parkway Belt	Enbridge SWDA	6.12912	0.2015
15	Union Parkway Belt	Union SWDA	6.18511	0.2034
16	Union Parkway Belt	Spruce	32.75736	1.0770
17	Union Parkway Belt	Emerson 1	30.86011	1.0146
18	Union Parkway Belt	Emerson 2	30.86011	1.0146
19	Union Parkway Belt	St. Clair	6.49976	0.2137
20	Union Parkway Belt	Dawn Export	6.12912	0.2015
21	Union Parkway Belt	Niagara Falls	4.66442	0.1534
22	Union Parkway Belt	Chippawa	4.70159	0.1546
23	Union Parkway Belt	Iroquois	9.24034	0.3038
24	Union Parkway Belt	Cornwall	9.89920	0.3255
25	Union Parkway Belt	Napierville	12.28888	0.4040
26	Union Parkway Belt	Philipsburg	12.56045	0.4130
27	Union Parkway Belt	East Hereford	15.43962	0.5076
28	Union Parkway Belt	Welwyn	37.26438	1.2251
29	Union SSMDA	Empress	-	1.1945
30	Union SSMDA	TransGas SSDA	-	0.9726
31	Union SSMDA	Centram SSDA	-	0.8817
32	Union SSMDA	Centram MDA	-	0.7442
33	Union SSMDA	Centrat MDA	-	0.7438
34	Union SSMDA	Union WDA	-	1.0008
35	Union SSMDA	Nipigon WDA	-	1.0780
36	Union SSMDA	Union NDA	-	0.7852
37	Union SSMDA	Calstock NDA	-	1.0008
38	Union SSMDA	Tunis NDA	-	0.8676
39	Union SSMDA	GMIT NDA	-	0.7687
40	Union SSMDA	Union SSMDA	-	0.0855
41	Union SSMDA	Union NCDA	-	0.6068
42	Union SSMDA	Union CDA	-	0.5153
43	Union SSMDA	Enbridge CDA	-	0.5467
44	Union SSMDA	Union EDA	-	0.6776
45	Union SSMDA	Enbridge EDA	-	0.7479
46	Union SSMDA	GMIT EDA	-	0.8391
47	Union SSMDA	KPUC EDA	-	0.6681
48	Union SSMDA	North Bay Junction	-	0.6965
49	Union SSMDA	Kirkwall	-	0.4931
50	Union SSMDA	Enbridge SWDA	-	0.3967
51	Union SSMDA	Union SWDA	-	0.3948
52	Union SSMDA	Spruce	-	0.7438
53	Union SSMDA	Emerson 1	-	0.6712
54	Union SSMDA	Emerson 2	-	0.6712
55	Union SSMDA	St. Clair	-	0.3845
56	Union SSMDA	Dawn Export	-	0.3967
57	Union SSMDA	Niagara Falls	-	0.5501
58	Union SSMDA	Chippawa	-	0.5513
59	Union SSMDA	Iroquois	-	0.7310
60	Union SSMDA	Cornwall	-	0.7526
61	Union SSMDA	Napierville	-	0.8312
62	Union SSMDA	Philipsburg	-	0.8401
63	Union SSMDA	East Hereford	-	0.9348
64	Union SSMDA	Welwyn	-	0.8817
65	Union WDA	Empress	-	0.8562
66	Union WDA	TransGas SSDA	-	0.6343
67	Union WDA	Centram SSDA	-	0.5434
68	Union WDA	Centram MDA	-	0.4067
69	Union WDA	Centrat MDA	-	0.3437
70	Union WDA	Union WDA	-	0.0855
71	Union WDA	Nipigon WDA	-	0.1864
72	Union WDA	Union NDA	-	0.5674
73	Union WDA	Calstock NDA	-	0.3519

uniongas

TRANSPORTATION RATES

(A) Applicability

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

Applicable Points

Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).

Dawn as a delivery point: Dawn (Facilities).

(B) Services

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

(C) Rates

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

	Monthly Demand Charge (applied to daily contract demand) Rate/GJ	**Commodity and Fuel Charges**		
		Fuel Ratio %	**AND**	**Commodity Charge Rate/GJ**
Firm Transportation (1)				
Dawn to Parkway	$2.382			
Dawn to Kirkwall	$2.011	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Kirkwall to Parkway	$0.372			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$2.961	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$5.718	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$5.718			
Parkway (TCPL) to Parkway (Cons) (2)		0.153%		

Authorized Overrun (3)

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

Transportation Overrun	**If Union supplies fuel Commodity Charge Rate/GJ**	**Commodity and Fuel Charges**		
		Fuel Ratio %	**AND**	**Commodity Charge Rate/GJ**
Dawn to Parkway				$0.078
Dawn to Kirkwall		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.066
Kirkwall to Parkway				$0.012
Parkway to Dawn				$0.078
Parkway (TCPL) Overrun (4)	n/a	0.648%		n/a
M12-X Firm Transportation Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.097

Current M12 Rates and Fuel

Current OEB approved rates effective July 1, 2013

		Contracted Quantity			Authorized Overrun	
Receipt Point	**Delivery Point**	**Daily Demand Charge $CDN/GJ**	**Month**	**Fuel %**	**Daily Variable Charge $CDN/GJ**	**Fuel %**
Dawn	Parkway	$0.078	January	1.086%	$0.078	1.686%
			February	1.033%		1.633%
			March	0.972%		1.572%
			April	0.802%		1.402%
			May	0.567%		1.167%
			June	0.463%		1.063%
			July	0.451%		1.051%
			August	0.355%		0.955%
			September	0.352%		0.952%
			October	0.697%		1.297%
			November	0.840%		1.440%
			December	0.945%		1.545%
Dawn	Kirkwall	$0.066	January	0.831%	$0.066	1.431%
			February	0.786%		1.386%
			March	0.719%		1.319%
			April	0.533%		1.133%
			May	0.359%		0.959%
			June	0.260%		0.860%
			July	0.248%		0.848%
			August	0.154%		0.754%
			September	0.154%		0.754%
			October	0.463%		1.063%
			November	0.603%		1.203%
			December	0.702%		1.302%
Kirkwall	Parkway	$0.012	January	0.408%	$0.012	1.008%
			February	0.400%		1.000%
			March	0.406%		1.006%
			April	0.422%		1.022%
			May	0.361%		0.961%
			June	0.357%		0.957%
			July	0.356%		0.956%
			August	0.354%		0.954%
			September	0.351%		0.951%
			October	0.387%		0.987%
			November	0.389%		0.989%
			December	0.396%		0.996%

Service	**Description**	**Daily Demand Charge $CDN/GJ**
F24-T	Firm All Day Transportation	$0.00224

Notes:

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

If you have any questions please contact your Account Manager

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

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

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

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.2501	0.0000	$7.7745	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0018	0.0018	0.0018	0.0018
Usage and ACA Charge	0.0018	0.0018	0.0018	0.0018

Negotiated Rates:

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

Rate Schedule FT-L 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum
Reservation Charge ($ per Dth per month)	$0.8391	0.0000	$5.2182	0.0000
Usage Charge ($ per Dth)	0.0135	0.0000	0.0840	0.0000
ACA Charge	0.0018	0.0018	0.0018	0.0018
Usage and ACA Charge	0.0153	0.0018	0.0858	0.0018

Negotiated Rates:

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

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

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

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

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s):

	Maximum Daily Reservation Quantity Dth
Alliance Interconnect	**17,172**

8. Primary Delivery Point(s):

	Maximum Daily Reservation Quantity Dth
St. Clair (US) Interconnect	**17,172**

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper:

Name: DON TUCCHENSKY
Title: ANALYST
Telephone: (508) 836-7259
Fax: (___) 508-870-2294

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s):

	Maximum Daily Reservation Quantity Dth
Washington 10 Interconnect	**17,086**

8. Primary Delivery Point(s):

	Maximum Daily Reservation Quantity Dth
St. Clair (US) Interconnect	**17,086**

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: ______

Name: DON TULCHINSKY

Title: ANALYST

Telephone: (___) 508-836 7257

Fax: (___) 508-870-2294

Historic TransCanada Fuel Loss Percentages

	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Winter Fuel Average	Summer Fuel Average	Last 12 Months
Union Parkway Belt - Iroquois	0.88%	0.93%	0.76%	0.86%	1.15%	1.20%	1.47%	1.41%	1.66%	1.21%	1.03%	0.92%	1.38%	0.94%	1.12%
Union Dawn - East Hereford	0.37%	0.50%	0.31%	0.52%	0.92%	1.21%	1.65%	1.74%	1.91%	1.05%	0.64%	0.65%	1.49%	0.58%	0.96%

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Average
Vector	Alliance	W-10	1.02%	0.87%	1.15%	1.20%	1.41%	1.33%	1.20%	0.40%	0.27%	0.40%	0.81%	1.05%	0.93%
Vector	Alliance	Dawn	1.02%	0.87%	1.15%	1.20%	1.41%	1.33%	1.20%	0.40%	0.27%	0.40%	0.81%	1.05%	0.93%
Vector	W-10 Storage	Dawn					0.50%	0.44%	0.40%	0.13%	0.14%				0.32%

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

SHIPPER:

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

INVOICES, STATEMENTS AND NOMINATIONS

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

ALL OTHER MATTERS

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

ARTICLE VIII: FURTHER AGREEMENT

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

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

EXHIBIT I

Rates:

Monthly Deliverability Rate: $ 2.4754 per Dth

Monthly Capacity Rate: $ 0.0238 per Dth

Injection Rate: $ 0.00 per Dth

Withdrawal Rate: $ 0.00 per Dth

Authorized Overrun Rate: $ 0.05 per Dth

Interruptible Rate: $ 0.05 per Dth

Service Parameters:

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

Maximum Daily Injection Quantity (MDIQ):

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

Maximum Daily Withdrawal Quantity (MDWQ):

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

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

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

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

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

DTE Energy

Gas Midstream Services

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DTE Gas Storage - Washington 10 Historic Fuel Rates

Effective Date	Injection	Withdrawal	Wheel From Hub to MichCon	Wheel From Hub to Vector
Apr 1, 2012	1.10%	0.40%	0.00%	0.50%
Nov 1, 2011	1.10%	0.40%	0.00%	0.50%
Apr 1, 2011	1.10%	0.40%	0.60%	0.60%
Feb 1, 2011	1.00%	0.50%	0.60%	0.60%
Nov 1, 2010	1.00%	0.50%	0.30%	0.30%
Apr 1, 2010	1.00%	0.40%	0.30%	0.30%
Mar 10, 2010	1.00%	0.40%	0.45%	0.45%
Mar 3, 2010	1.00%	0.40%	0.00%	0.00%
Mar 1, 2010	1.00%	0.40%	0.45%	0.45%
Nov 1, 2009	0.00%	0.40%	n/a	n/a
Apr 1, 2009	0.95%	0.00%	n/a	n/a
Nov 1, 2008	0.00%	0.55%	n/a	n/a
Apr 1, 2008	0.70%	0.50%	n/a	n/a
Nov 1, 2007	0.00%	0.70%	n/a	n/a
Apr 1, 2007	0.70%	0.00%	n/a	n/a
Dec 1, 2006	0.00%	0.30%	n/a	n/a
Apr 1, 2006	0.50%	0.00%	n/a	n/a
Nov 1, 2005	0.00%	0.50%	n/a	n/a
Apr 1, 2005	0.72%	0.00%	n/a	n/a
Nov 1, 2004	0.00%	0.50%	n/a	n/a
Apr 1, 2004	0.58%	0.00%	n/a	n/a

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Northern Utilities, Inc.
Retail Marketer Capacity Assignment Revenue Projections
November 2013 through October 2014

Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (3,502,994)	Page 2
NH Division Storage Contract Capacity Assignment	$ (307,481)	Page 3
NH Division Peaking Demand	$ (509,847)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 924,882	Page 5
NH Division PNGTS Litigation Costs Assigned to Retail Suppliers	$ (2,344)	Page 6
NH Division Capacity Assignment Demand Revenue (excluding PNGTS Refund)	$ (3,397,784)	Sum of Items Above
NH Division PNGTS Refund Assigned to Retail Suppliers	$ 62,178	Page 6
NH Division Capacity Assignment Demand Revenue (including PNGTS Refund)	$ (3,335,606)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2013 through October 31, 2014

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	Assigned Pipeline Credits	Assigned Storage Credits	NH Annual Cap Assign Credit
Algonquin	93002F	$ 308,943	$ -	Y	4,211	-	(508)	-	$ (37,270)	$ -	$ (37,270)
Algonquin	93201A1C	$ 98,680	$ -	Y	1,251	-	(151)	-	$ (11,911)	$ -	$ (11,911)
Granite	10-010-FT-NN	$ 766,454	$ 1,124,472	Y	24,217	35,529	(2,920)	(3,601)	$ (92,416)	$ (113,969)	$ (206,386)
Granite	10-010-FT-NN	$ 271,853	$ 398,838	Y	24,217	35,529	(2,920)	(3,601)	$ (32,779)	$ (40,424)	$ (73,203)
Iroquois	R181001	$ 520,036	$ -	Y	6,569	-	(792)	-	$ (62,699)	$ -	$ (62,699)
PNGTS	1997-003	$ 531,242	$ -	Y	1,100	-	(133)	-	$ (64,232)	$ -	$ (64,232)
PNGTS	1997-004	$ -	$ 12,616,989	Y	-	33,000	-	(3,344)	$ -	$ (1,278,522)	$ (1,278,522)
Tennessee	5083	$ 1,351,367	$ -	Y	4,605	-	(555)	-	$ (162,868)	$ -	$ (162,868)
Tennessee	5083	$ 2,225,558	$ -	Y	8,550	-	(1,031)	-	$ (268,368)	$ -	$ (268,368)
Tennessee	5265	$ -	$ 270,275	Y	-	2,653	-	(269)	$ -	$ (27,404)	$ (27,404)
Tennessee	5292	$ 125,521	$ -	Y	1,406	-	(170)	-	$ (15,177)	$ -	$ (15,177)
Tennessee	31861	$ 198,727	$ -	Y	2,226	-	(268)	-	$ (23,926)	$ -	$ (23,926)
Tennessee	39735	$ 82,937	$ -	Y	929	-	(112)	-	$ (9,999)	$ -	$ (9,999)
Tennessee	41099	$ 380,937	$ -	Y	4,267	-	(515)	-	$ (45,977)	$ -	$ (45,977)
Texas Eastern	800384	$ 66,747	$ -	N	NA	NA	-	-	$ -	$ -	$ -
TransCanada	33322	$ -	$ 8,255,594	Y	-	34,000	-	(3,446)	$ -	$ (836,729)	$ (836,729)
TransCanada	29594	$ 714,000	$ -	Y	5,937	-	(716)	-	$ (86,108)	$ -	$ (86,108)
Union	M12205	$ 177,706	$ -	Y	6,003	-	(724)	-	$ (21,432)	$ -	$ (21,432)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	Y	-	17,172	-	(1,740)	$ -	$ (158,776)	$ (158,776)
Vector	CRL-NUI-0727	$ -	$ 389,774	Y	-	17,086	-	(1,732)	$ -	$ (39,511)	$ (39,511)
Vector	FT-1-NUI-0122	$ 566,295	$ -	Y	6,070	-	(732)	-	$ (68,291)	$ -	$ (68,291)
Vector	FT-1-NUI-C0122	$ 34,876	$ -	Y	6,070	-	(732)	-	$ (4,206)	$ -	$ (4,206)
Total NH Capacity Assignment Credits									$ (1,007,659)	$ (2,495,335)	$ (3,502,994)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 2013 through October 2014

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	(26,282)	(430)	$ (14,601)
W-10	01052	$ 2,890,000	Y	Y	(344,565)	(3,446)	$ (292,880)

Total NH Division Storage Capacity Assignment	$ (307,481)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
New Hampshire Division
Peaking Demand Capacity Assignment Revenues
November 2013 through October 2014

Month	Total Peaking Demand TCQ	Rate	Demand Revenue
Nov-13	4,654	$ 18.26	$ (84,974)
Dec-13	4,654	$ 18.26	$ (84,974)
Jan-14	4,654	$ 18.26	$ (84,974)
Feb-14	4,654	$ 18.26	$ (84,974)
Mar-14	4,654	$ 18.26	$ (84,974)
Apr-14	4,654	$ 18.26	$ (84,974)

Total Division Peaking Demand Revenue $ (509,847)

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Northern Utilities, Inc.
New Hampshire Division
Asset Management and Capacity Release Revenue Assigned to Retail Suppliers
November 2013 through October 2014

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	[redacted]	Yes	Pipeline	12.06%	[redacted]
Algonquin Contract #93201A1C (1,251 Dth)	[redacted]	Yes	Pipeline	12.06%	[redacted]
Wash 10 via Vector, TCPL, PNGTS	[redacted]	Yes	Storage	10.13%	[redacted]
Tennessee Niagara	[redacted]	No	Pipeline	12.06%	[redacted]
Tennessee Long-Haul	[redacted]	No	Pipeline	12.06%	[redacted]
Total Asset Management	$ (11,805,500)				$ 924,882

Capacity Release Revenue					
Resources	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Texas Eastern Contract 800384	$ (66,747)	No	Pipeline	12.06%	$ -
Tennessee 5265	$ (83,950)	No	Pipeline	12.06%	$ -
Total Capacity Release	$ (150,697)				$ -

Total Asset Management and Capacity Release Revenue	$ (11,956,197)	$ 924,882

Northern Utilities, Inc.
New Hampshire Division
PNGTS 2008 Rate Case Refund and Rate Case Litigation Costs Assigned to Retail Suppliers
November 2013 through October 2014

PNGTS Litigation Costs	$ 22,988

PNGTS Contract	MDQ	Percentage MDQ	Allocated PNGTS Litigation Items	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ 742	Pipeline	12.06%	$ (89)
PNGTS Contract 1997-004	33,000	97%	$ 22,246	Storage	10.13%	$ (2,255)
PNGTS Total	34,100	100%	$ 22,988			$ (2,344)

PNGTS 2008 Rate Case Refund	$ (609,808)

PNGTS Contract	MDQ	Percentage MDQ	Allocated PNGTS Litigation Items	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ (19,671)	Pipeline	12.06%	$ 2,372
PNGTS Contract 1997-004	33,000	97%	$ (590,136)	Storage	10.13%	$ 59,806
PNGTS Total	34,100	100%	$ (609,808)			$ 62,178

Estimated Net Refund to NH Sales Service Customers	$ (547,629)

Northern Utilities, Inc.
NH Division Peaking Capacity Assignment Demand Rate
November 2013 through April 2014

Line	Description	Northern	NH Division
1	Capacity Allocation Factor		47.24%
2	Peaking Contracts	19,948	9,423
3	Peaking Plants	10,000	4,724
4	Total	29,948	14,147
5	Peaking Contracts Costs	$ 903,750	$ 426,932
6	Peaking Allocated Pipeline Demand Costs	$ 1,725,894	$ 815,312
7	Peaking Plants		$ 307,762
8	Capacity Costs (Before Cap Assignment)		$ 1,550,006
9	NH Division Peaking Capacity Assignment Rate		$ 18.26

	Reservation Refund			Interest Amount			Total Refund			PR Allocator		Refund Allocation	
Billing Period	1997-003	1997-004	Total	1997-003	1997-004	Total	1997-003	1997-004	Total	ME	NH	ME	NH
Sep-08	$ 1,702.25	$ -	$ 1,702.25	$ 2.56	$ -	$ 2.56	$ 1,704.81	$ -	$ 1,704.81	49.93%	50.07%	$ 851.21	$ 853.60
Oct-08	$ 1,702.25	$ -	$ 1,702.25	$ 9.30	$ -	$ 9.30	$ 1,711.55	$ -	$ 1,711.55	49.93%	50.07%	$ 854.58	$ 856.97
Nov-08	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 16.98	$ 145.81	$ 162.78	$ 1,719.23	$ 97,172.41	$ 98,891.63	49.91%	50.09%	$ 49,356.81	$ 49,534.82
Dec-08	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 21.98	$ 504.64	$ 526.62	$ 1,724.23	$ 97,531.24	$ 99,255.47	49.91%	50.09%	$ 49,538.41	$ 49,717.07
Jan-09	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 25.44	$ 768.98	$ 794.42	$ 1,727.69	$ 97,795.58	$ 99,523.27	49.91%	50.09%	$ 49,672.07	$ 49,851.21
Feb-09	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 35.15	$ 1,252.51	$ 1,287.66	$ 1,737.40	$ 98,279.11	$ 100,016.51	49.91%	50.09%	$ 49,918.24	$ 50,098.27
Mar-09	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 30.06	$ 1,170.51	$ 1,200.57	$ 1,732.31	$ 98,197.11	$ 99,929.42	49.91%	50.09%	$ 49,874.77	$ 50,054.65
Apr-09	$ 1,702.25	$ -	$ 1,702.25	$ 36.21	$ 1,394.67	$ 1,430.88	$ 1,738.46	$ 1,394.67	$ 3,133.13	49.91%	50.09%	$ 1,563.74	$ 1,569.38
May-09	$ 1,702.25	$ -	$ 1,702.25	$ 39.65	$ 1,353.37	$ 1,393.02	$ 1,741.90	$ 1,353.37	$ 3,095.27	49.91%	50.09%	$ 1,544.85	$ 1,550.42
Jun-09	$ 1,702.25	$ -	$ 1,702.25	$ 44.43	$ 1,356.04	$ 1,400.47	$ 1,746.68	$ 1,356.04	$ 3,102.72	49.91%	50.09%	$ 1,548.57	$ 1,554.15
Jul-09	$ 1,702.25	$ -	$ 1,702.25	$ 49.33	$ 1,356.04	$ 1,405.37	$ 1,751.58	$ 1,356.04	$ 3,107.62	49.91%	50.09%	$ 1,551.01	$ 1,556.61
Aug-09	$ 1,702.25	$ -	$ 1,702.25	$ 52.19	$ 1,315.89	$ 1,368.08	$ 1,754.44	$ 1,315.89	$ 3,070.33	49.91%	50.09%	$ 1,532.40	$ 1,537.93
Sep-09	$ 1,702.25	$ -	$ 1,702.25	$ 58.88	$ 1,367.19	$ 1,426.07	$ 1,761.13	$ 1,367.19	$ 3,128.32	49.91%	50.09%	$ 1,561.35	$ 1,566.98
Oct-09	$ 1,702.25	$ -	$ 1,702.25	$ 61.70	$ 1,323.09	$ 1,384.79	$ 1,763.95	$ 1,323.09	$ 3,087.04	49.91%	50.09%	$ 1,540.74	$ 1,546.30
Nov-09	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 68.55	$ 1,466.16	$ 1,534.71	$ 1,770.80	$ 98,492.76	$ 100,263.56	52.54%	47.46%	$ 52,678.47	$ 47,585.09
Dec-09	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 73.45	$ 1,741.12	$ 1,814.57	$ 1,775.70	$ 98,767.72	$ 100,543.42	52.54%	47.46%	$ 52,825.51	$ 47,717.91
Jan-10	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 70.61	$ 1,797.81	$ 1,868.42	$ 1,772.86	$ 98,824.41	$ 100,597.27	52.54%	47.46%	$ 52,853.80	$ 47,743.46
Feb-10	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 83.20	$ 2,282.18	$ 2,365.38	$ 1,785.45	$ 99,308.78	$ 101,094.23	52.54%	47.46%	$ 53,114.91	$ 47,979.32
Mar-10	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 85.17	$ 2,471.70	$ 2,556.87	$ 1,787.42	$ 99,498.30	$ 101,285.72	52.54%	47.46%	$ 53,215.52	$ 48,070.20
Apr-10	$ 1,702.25	$ -	$ 1,702.25	$ 93.25	$ 2,732.64	$ 2,825.88	$ 1,795.50	$ 2,732.64	$ 4,528.13	52.54%	47.46%	$ 2,379.08	$ 2,149.05
May-10	$ 1,702.25	$ -	$ 1,702.25	$ 94.69	$ 2,651.47	$ 2,746.16	$ 1,796.94	$ 2,651.47	$ 4,448.41	52.54%	47.46%	$ 2,337.19	$ 2,111.21
Jun-10	$ 1,702.25	$ -	$ 1,702.25	$ 102.92	$ 2,754.28	$ 2,857.20	$ 1,805.17	$ 2,754.28	$ 4,559.45	52.54%	47.46%	$ 2,395.54	$ 2,163.92
Jul-10	$ 1,702.25	$ -	$ 1,702.25	$ 108.12	$ 2,754.28	$ 2,862.41	$ 1,810.37	$ 2,754.28	$ 4,564.66	52.54%	47.46%	$ 2,398.27	$ 2,166.39
Aug-10	$ 1,702.25	$ -	$ 1,702.25	$ 109.09	$ 2,672.71	$ 2,781.80	$ 1,811.34	$ 2,672.71	$ 4,484.05	52.54%	47.46%	$ 2,355.92	$ 2,128.13
Sep-10	$ 1,702.25	$ -	$ 1,702.25	$ 117.84	$ 2,776.84	$ 2,894.69	$ 1,820.09	$ 2,776.84	$ 4,596.94	52.54%	47.46%	$ 2,415.23	$ 2,181.71
Oct-10	$ 1,702.25	$ -	$ 1,702.25	$ 119.06	$ 2,687.27	$ 2,806.33	$ 1,821.31	$ 2,687.27	$ 4,508.58	52.54%	47.46%	$ 2,368.81	$ 2,139.77
Nov-10	$ 1,702.25	$ 97,026.60	$ 98,728.85	$ 127.83	$ 2,879.86	$ 3,007.69	$ 1,830.08	$ 99,906.46	$ 101,736.54	51.36%	48.64%	$ 52,251.89	$ 49,484.65
Dec-10	$ -	$ -	$ -	$ 131.23	$ 3,067.16	$ 3,198.39	$ 131.23	$ 3,067.16	$ 3,198.39	51.36%	48.64%	$ 1,642.69	$ 1,555.70
Jan-11	$ -	$ -	$ -	$ 119.13	$ 2,770.34	$ 2,889.47	$ 119.13	$ 2,770.34	$ 2,889.47	51.36%	48.64%	$ 1,484.03	$ 1,405.44
Feb-11	$ -	$ -	$ -	$ 131.89	$ 3,075.89	$ 3,207.78	$ 131.89	$ 3,075.89	$ 3,207.78	51.36%	48.64%	$ 1,647.52	$ 1,560.26
Mar-11	$ -	$ -	$ -	$ 127.98	$ 2,992.01	$ 3,119.99	$ 127.98	$ 2,992.01	$ 3,119.99	51.36%	48.64%	$ 1,602.43	$ 1,517.56
Apr-11	$ -	$ -	$ -	$ 132.95	$ 3,091.74	$ 3,224.69	$ 132.95	$ 3,091.74	$ 3,224.69	51.36%	48.64%	$ 1,656.20	$ 1,568.49
May-11	$ -	$ -	$ -	$ 128.66	$ 3,000.18	$ 3,128.84	$ 128.66	$ 3,000.18	$ 3,128.84	51.36%	48.64%	$ 1,606.97	$ 1,521.87
Jun-11	$ -	$ -	$ -	$ 133.33	$ 3,117.07	$ 3,250.40	$ 133.33	$ 3,117.07	$ 3,250.40	51.36%	48.64%	$ 1,669.41	$ 1,581.00
Jul-11	$ -	$ -	$ -	$ 134.03	$ 3,117.07	$ 3,251.10	$ 134.03	$ 3,117.07	$ 3,251.10	51.36%	48.64%	$ 1,669.76	$ 1,581.33
Aug-11	$ -	$ -	$ -	$ 129.70	$ 3,024.76	$ 3,154.46	$ 129.70	$ 3,024.76	$ 3,154.46	51.36%	48.64%	$ 1,620.13	$ 1,534.33
Sep-11	$ -	$ -	$ -	$ 134.42	$ 3,142.61	$ 3,277.02	$ 134.42	$ 3,142.61	$ 3,277.02	51.36%	48.64%	$ 1,683.08	$ 1,593.94
Oct-11	$ -	$ -	$ -	$ 130.77	$ 3,041.23	$ 3,172.00	$ 130.77	$ 3,041.23	$ 3,172.00	51.36%	48.64%	$ 1,629.14	$ 1,542.86
Nov-11	$ -	$ -	$ -	$ 135.13	$ 3,151.64	$ 3,286.77	$ 135.13	$ 3,151.64	$ 3,286.77	52.62%	47.38%	$ 1,729.50	$ 1,557.27
Dec-11	$ -	$ -	$ -	$ 135.15	$ 3,159.41	$ 3,294.56	$ 135.15	$ 3,159.41	$ 3,294.56	52.62%	47.38%	$ 1,733.60	$ 1,560.96
Jan-12	$ -	$ -	$ -	$ 127.09	$ 2,955.58	$ 3,082.67	$ 127.09	$ 2,955.58	$ 3,082.67	52.62%	47.38%	$ 1,622.10	$ 1,460.57
Feb-12	$ -	$ -	$ -	$ 135.86	$ 3,168.48	$ 3,304.34	$ 135.86	$ 3,168.48	$ 3,304.34	52.62%	47.38%	$ 1,738.74	$ 1,565.59
Mar-12	$ -	$ -	$ -	$ 131.83	$ 3,082.21	$ 3,214.04	$ 131.83	$ 3,082.21	$ 3,214.04	52.62%	47.38%	$ 1,691.23	$ 1,522.81
Apr-12	$ -	$ -	$ -	$ 136.96	$ 3,184.95	$ 3,321.91	$ 136.96	$ 3,184.95	$ 3,321.91	52.62%	47.38%	$ 1,747.99	$ 1,573.92
May-12	$ -	$ -	$ -	$ 132.54	$ 3,090.60	$ 3,223.14	$ 132.54	$ 3,090.60	$ 3,223.14	52.62%	47.38%	$ 1,696.02	$ 1,527.13
Jun-12	$ -	$ -	$ -	$ 137.35	$ 3,210.97	$ 3,348.32	$ 137.35	$ 3,210.97	$ 3,348.32	52.62%	47.38%	$ 1,761.89	$ 1,586.43
Jul-12	$ -	$ -	$ -	$ 138.06	$ 3,210.97	$ 3,349.04	$ 138.06	$ 3,210.97	$ 3,349.04	52.62%	47.38%	$ 1,762.26	$ 1,586.77
Aug-12	$ -	$ -	$ -	$ 133.61	$ 3,115.85	$ 3,249.46	$ 133.61	$ 3,115.85	$ 3,249.46	52.62%	47.38%	$ 1,709.87	$ 1,539.60
Sep-12	$ -	$ -	$ -	$ 138.46	$ 3,237.20	$ 3,375.67	$ 138.46	$ 3,237.20	$ 3,375.67	52.62%	47.38%	$ 1,776.28	$ 1,599.39
Oct-12	$ -	$ -	$ -	$ 134.70	$ 3,132.78	$ 3,267.48	$ 134.70	$ 3,132.78	$ 3,267.48	52.62%	47.38%	$ 1,719.35	$ 1,548.13
Nov-12	$ -	$ -	$ -	$ 139.19	$ 3,246.48	$ 3,385.68	$ 139.19	$ 3,246.48	$ 3,385.68	53.60%	46.40%	$ 1,814.72	$ 1,570.95
Dec-12	$ -	$ -	$ -	$ 139.98	$ 3,272.30	$ 3,412.28	$ 139.98	$ 3,272.30	$ 3,412.28	53.60%	46.40%	$ 1,828.98	$ 1,583.30
Jan-13	$ -	$ -	$ -	$ 127.10	$ 2,955.63	$ 3,082.72	$ 127.10	$ 2,955.63	$ 3,082.72	53.60%	46.40%	$ 1,652.34	$ 1,430.38
Feb-13	$ -	$ -	$ -	$ 140.71	$ 3,281.60	$ 3,422.32	$ 140.71	$ 3,281.60	$ 3,422.32	53.60%	46.40%	$ 1,834.36	$ 1,587.96
Mar-13	$ -	$ -	$ -	$ 136.54	$ 3,192.11	$ 3,328.65	$ 136.54	$ 3,192.11	$ 3,328.65	53.60%	46.40%	$ 1,784.16	$ 1,544.49
Apr-13	$ -	$ -	$ -	$ 91.51	$ 2,128.08	$ 2,219.59	$ 91.51	$ 2,128.08	$ 2,219.59	53.60%	46.40%	$ 1,189.70	$ 1,029.89
Total	**$ 45,960.75**	**$ 1,067,292.60**	**$ 1,113,253.35**	**$ 5,563.50**	**$ 134,194.00**	**$ 139,757.50**	**$ 51,524.25**	**$ 1,201,486.60**	**$ 1,253,010.85**	**51.33%**	**48.67%**	**$ 643,203.34**	**$ 609,807.51**

Northern Utilities, Inc.
Summary of PNGTS Litigation Expenses, 8/1/2012 - 7/31/2013
New Hampshire Division

Period	NH Division Amount	Reference
8/1/2012 - 7/31/2013	$ 22,987.94	Page 2 of 2
Period Total	$ 22,987.94	

Northern Utilities, Inc.
Expenses Incurred to Oppose Proposed PNGTS Rate Increases
Amounts Paid from August 1, 2012 through July 31, 2013

Service Provider	Expense	New Hampshire Allocated Expenses
BATES WHITE LLC Total	$ 5,700.00	$ 2,700.66
JEFFRY FINK Total	$ 1,208.40	$ 560.70
WINSTEAD PC Total	$ 42,514.18	$ 19,726.58
Grand Total	$ 49,422.58	$ 22,987.94

Schedules 6A and 6B

Northern Utilities, Inc.
Commodity Cost by Supply Source
November 2013 through April 2014

Description	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Season
Pipeline Supplies							
Tenn Zone 4 Spot	$ 245,301	$ 293,666	$ -	$ -	$ 69,020	$ 279,498	$ 887,485
Tennessee Production	$ 591,358	$ 1,043,379	$ 627,411	$ 569,279	$ 533,916	$ 1,314,622	$ 4,679,966
Chicago	$ 708,095	$ 780,136	$ 795,692	$ 718,689	$ 789,040	$ -	$ 3,791,653
Algonquin Receipts	$ 148,403	$ 181,822	$ 186,684	$ 164,297	$ 162,843	$ -	$ 844,050
TGP Zone 6	$ -	$ -	$ -	$ -	$ -	$ 252,686	$ 252,686
Niagara	$ 260,812	$ 294,242	$ 299,518	$ 270,532	$ 282,403	$ 191,598	$ 1,599,104
Iroquois Receipts	$ 94,638	$ 116,152	$ 117,787	$ 106,388	$ 77,868	$ -	$ 512,833
PNGTS	$ 180,079	$ 190,657	$ 192,945	$ 174,273	$ 191,969	$ -	$ 929,923
PNGTS Delivered	$ 213,780	$ 225,482	$ 227,770	$ 205,728	$ 226,793	$ -	$ 1,099,553
Lewiston Baseload	$ 1,670,370	$ 1,759,095	$ 1,775,618	$ 1,603,784	$ 1,768,565	$ 199,080	$ 8,776,512
Company Managed Pipeline	$ (94,287)	$ (104,313)	$ (106,691)	$ (95,976)	$ (103,586)	$ -	$ (504,853)
Subtotal Pipeline	$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 22,868,912
Underground Storage							
Tennessee Storage	$ -	$ -	$ 289,189	$ 261,203	$ 209,128	$ -	$ 759,520
Washington 10 Storage	$ 314,389	$ 2,032,584	$ 3,426,273	$ 2,868,653	$ 1,485,093	$ -	$ 10,126,992
Company-Managed Storage	$ (263,862)	$ (1,160,995)	$ (1,583,176)	$ (1,424,858)	$ (844,360)	$ -	$ (5,277,250)
Subtotal Storage	$ 50,528	$ 871,589	$ 2,132,286	$ 1,704,998	$ 849,861	$ -	$ 5,609,262
Peaking Supplies							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 3	$ -	$ -	$ 2,519,619	$ 1,517,530	$ -	$ -	$ 4,037,149
LNG	$ 9,135	$ 9,824	$ 9,902	$ 9,434	$ 10,357	$ 21,201	$ 69,852
Company Managed LNG	$ -	$ -	$ (21,895)	$ -	$ -	$ -	$ (21,895)
Subtotal Peaking	$ 9,135	$ 9,824	$ 2,507,626	$ 1,526,964	$ 10,357	$ 21,201	$ 4,085,106
Total NUI Commodity	$ 4,436,362	$ 6,927,040	$ 10,468,406	$ 8,469,790	$ 5,806,996	$ 2,258,685	$ 38,367,279
Company-Managed (NH & ME)	$ (358,149)	$ (1,265,308)	$ (1,711,762)	$ (1,520,833)	$ (947,947)	$ -	$ (5,803,998)
Sales Service (NH & ME)	$ 4,078,213	$ 5,661,732	$ 8,756,645	$ 6,948,957	$ 4,859,049	$ 2,258,685	$ 32,563,281
Net Commodity Costs	$ 4,078,213	$ 5,661,732	$ 8,756,645	$ 6,948,957	$ 4,859,049	$ 2,258,685	$ 32,563,281

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2013 through April 2014

Description	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Season
Pipeline Supplies							
Tenn Zone 4 Spot	64,149	73,586	0	0	17,090	69,929	224,755
Tennessee Production	150,505	254,277	153,727	139,483	131,970	317,857	1,147,820
Chicago	170,113	179,674	179,674	162,286	179,746	0	871,493
AGT Receipts	37,530	38,781	38,781	35,028	38,781	0	188,901
TGP Zone 6	0	0	0	0	0	56,894	56,894
Niagara	58,317	63,433	63,433	57,294	60,261	44,454	347,191
Iroquois Receipts	16,506	19,688	19,688	17,783	13,094	0	86,760
PNGTS	26,906	27,802	27,802	25,112	27,802	0	135,424
PNGTS Delivered	26,906	27,802	27,802	25,112	27,802	0	135,424
Lewiston Baseload	195,000	201,500	201,500	182,000	201,500	45,000	1,026,500
Company Managed Pipeline	-23,280	-24,056	-24,056	-21,728	-24,056	0	-117,176
Subtotal Pipeline	722,652	862,488	688,352	622,370	673,991	534,134	4,103,987
Underground Storage							
Tennessee Storage	0	0	73,653	66,525	53,263	0	193,442
Washington 10 Storage	79,127	511,569	862,338	721,994	373,774	0	2,548,803
Company-Managed Storage	-66,410	-292,204	-398,460	-358,614	-212,512	0	-1,328,200
Subtotal Storage	12,717	219,365	537,532	429,905	214,525	0	1,414,044
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	155,481	93,644	0	0	249,125
LNG	1,350	1,395	1,395	1,260	1,395	3,065	9,860
Company Managed LNG	0	0	-3,108	0	0	0	-3,108
Subtotal Peaking	1,350	1,395	153,768	94,904	1,395	3,065	255,877
Total NUI Commodity	826,409	1,399,508	1,805,275	1,527,522	1,126,479	537,199	7,222,392
Company-Managed (NH & ME)	-89,690	-316,260	-425,624	-380,342	-236,568	0	-1,448,484
Sales Service (NH & ME)	736,719	1,083,248	1,379,651	1,147,180	889,911	537,199	5,773,908
Net Delivered (Dth)	736,719	1,083,248	1,379,651	1,147,180	889,911	537,199	5,773,908

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2013 through April 2014

Description	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Season
Pipeline Supplies							
Tenn Zone 4 Spot	$ 3.824	$ 3.991			$ 4.039	$ 3.997	$ 3.949
Tennessee Production	$ 3.929	$ 4.103	$ 4.081	$ 4.081	$ 4.046	$ 4.136	$ 4.077
Chicago	$ 4.163	$ 4.342	$ 4.429	$ 4.429	$ 4.390		$ 4.351
AGT Receipts	$ 3.954	$ 4.688	$ 4.814	$ 4.690	$ 4.199		$ 4.468
TGP Zone 6						$ 4.441	$ 4.441
Niagara	$ 4.472	$ 4.639	$ 4.722	$ 4.722	$ 4.686	$ 4.310	$ 4.606
Iroquois Receipts	$ 5.733	$ 5.899	$ 5.983	$ 5.983	$ 5.947		$ 5.911
PNGTS	$ 6.693	$ 6.858	$ 6.940	$ 6.940	$ 6.905		$ 6.867
PNGTS Delivered	$ 7.946	$ 8.110	$ 8.192	$ 8.192	$ 8.157		$ 8.119
Lewiston Baseload	$ 8.566	$ 8.730	$ 8.812	$ 8.812	$ 8.777	$ 4.424	$ 8.550
Company Managed Pipeline	$ 4.050	$ 4.336	$ 4.435	$ 4.417	$ 4.306		$ 4.309
Subtotal Pipeline	$ 5.561	$ 5.542	$ 5.981	$ 5.972	$ 5.933	$ 4.189	$ 5.572
Underground Storage							
Tennessee Storage			$ 3.926	$ 3.926	$ 3.926		$ 3.926
Washington 10 Storage	$ 3.973	$ 3.973	$ 3.973	$ 3.973	$ 3.973		$ 3.973
Company-Managed Storage	$ 3.973	$ 3.973	$ 3.973	$ 3.973	$ 3.973		$ 3.973
Subtotal Storage	$ 3.973	$ 3.973	$ 3.967	$ 3.966	$ 3.962		$ 3.967
Peaking Supplies							
Peaking Supply 1							
Peaking Supply 2							
Peaking Supply 3			$ 16.205	$ 16.205			$ 16.205
LNG	$ 6.766	$ 7.042	$ 7.098	$ 7.487	$ 7.424	$ 6.917	$ 7.084
Company Managed LNG			$ 7.045				$ 7.045
Subtotal Peaking	$ 6.766	$ 7.042	$ 16.308	$ 16.090	$ 7.424	$ 6.917	$ 15.965
Total NUI Commodity	$ 5.368	$ 4.950	$ 5.799	$ 5.545	$ 5.155	$ 4.205	$ 5.312
Company-Managed (NH & ME)	$ 3.993	$ 4.001	$ 4.022	$ 3.999	$ 4.007		$ 4.007
Sales Service (NH & ME)	$ 5.536	$ 5.227	$ 6.347	$ 6.057	$ 5.460	$ 4.205	$ 5.640
Net Cost per Dth	$ 5.536	$ 5.227	$ 6.347	$ 6.057	$ 5.460	$ 4.205	$ 5.640

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	65,276	74,878	-	-	17,390	71,157	228,700
2	City Gate Delivered Volume	Line 34	64,149	73,586	-	-	17,090	69,929	224,755
3	Total Purchase Cost	Line 15	$ 237,538	$ 284,761	$ -	$ -	$ 66,952	$ 271,036	$ 860,286
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 7,763	$ 8,905	$ -	$ -	$ 2,068	$ 8,463	$ 27,199
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 245,301	$ 293,666	$ -	$ -	$ 69,020	$ 279,498	$ 887,485
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.824	$ 3.991			$ 4.039	$ 3.997	$ 3.949
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	65,276	74,878	-	-	17,390	71,157	228,700
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.780
11	NYMEX Cost	Line 9 times Line 10	$ 239,300	$ 286,782	$ -	$ -	$ 67,421	$ 271,036	$ 864,539
12	NYMEX Basis Price	Att to Sch 5A, Line 10 of Page 1	$ (0.027)	$ (0.027)			$ (0.027)	$ -	$ (0.019)
13	NYMEX Basis Costs	Line 9 times Line 12	$ (1,762)	$ (2,022)	$ -	$ -	$ (470)	$ -	$ (4,254)
14	Total Purchase Price	Line 10 plus Line 12	$ 3.639	$ 3.803			$ 3.850	$ 3.809	$ 3.762
15	Total Purchase Cost	Line 11 plus Line 13	$ 237,538	$ 284,761	$ -	$ -	$ 66,952	$ 271,036	$ 860,286
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 300 Leg								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	65,276	74,878	-	-	17,390	71,157	228,700
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	64,375	73,845	-	-	17,150	70,175	225,544
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188
26	Variable Transportation Costs	Line 24 times Line 25	$ 7,648	$ 8,773	$ -	$ -	$ 2,037	$ 8,337	$ 26,795
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	64,375	73,845	-	-	17,150	70,175	225,544
33	Fuel Loss Rate	Att to Sch 5A, Line 39 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)	64,149	73,586	-	-	17,090	69,929	224,755
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 115	$ 132	$ -	$ -	$ 31	$ 126	$ 405

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	City Gate Volumes - Z0	Line 2 of Page 5	43,450	106,289	-	-	-	108,750	258,489
2	City Gate Volumes - Z1	Line 2 of Page 6	12,555	-	-	-	-	62,267	74,822
3	City Gate Volumes - Z4	Line 2 of Page 7	94,500	147,988	153,727	139,483	131,970	146,840	814,509
4	Total City Gate Volumes	Sum Lines 1 through 3	150,505	254,277	153,727	139,483	131,970	317,857	1,147,820
5	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ 177,180	$ 451,738	$ -	$ -	$ -	$ 459,796	$ 1,088,714
6	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 52,146	$ -	$ -	$ -	$ -	$ 267,924	$ 320,069
7	City Gate Delivered Costs - Z4	Line 5 of Page 7	$ 362,032	$ 591,641	$ 627,411	$ 569,279	$ 533,916	$ 586,902	$ 3,271,182
8	Total City Gate Delivered Costs	Sum Lines 5 through 7	$ 591,358	$ 1,043,379	$ 627,411	$ 569,279	$ 533,916	$ 1,314,622	$ 4,679,966
9	Average Delivered Price	Line 8 divided by Line 4	$ 3.929	$ 4.103	$ 4.081	$ 4.081	$ 4.046	$ 4.136	$ 4.077

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 32	45,652	111,677	-	-	-	114,262	271,591
2	City Gate Delivered Volume	Line 44	43,450	106,289	-	-	-	108,750	258,489
3	Total Purchase Price	Line 24	$ 3.542	$ 3.706				$ 3.685	$ 3.670
4	Total Purchase Cost	Line 2 times Line 3	$ 161,701	$ 413,874	$ -	$ -	$ -	$ 421,055	$ 996,630
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 15,479	$ 37,864	$ -	$ -	$ -	$ 38,741	$ 92,084
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 177,180	$ 451,738	$ -	$ -	$ -	$ 459,796	$ 1,088,714
7	Average Delivered Price	Line 6 divided by Line 2	$ 4.078	$ 4.250				$ 4.228	$ 4.212
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	$ 3.542	$ 3.706				$ 3.685	$ 3.670
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 0 Supply Costs</u>								
19	Purchased Volumes	Sendout Optimization	45,652	111,677	-	-	-	114,262	271,591
20	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.794
21	NYMEX Cost	Line 9 times Line 10	$ 167,362	$ 427,722	$ -	$ -	$ -	$ 435,224	$ 1,030,307
22	NYMEX Basis Price	Att to Sch 5A, Line 7 of Page 1	$ (0.124)	$ (0.124)				$ (0.124)	$ (0.124)
23	NYMEX Basis Costs	Line 9 times Line 12	$ (5,661)	$ (13,848)	$ -	$ -	$ -	$ (14,168)	$ (33,677)
24	Total Purchase Price	Line 10 plus Line 12	$ 3.542	$ 3.706				$ 3.685	$ 3.670
25	Total Purchase Cost	Line 11 plus Line 13	$ 161,701	$ 413,874	$ -	$ -	$ -	$ 421,055	$ 996,630
26									
27	<u>Transportation Fuel Losses and Variable Charges</u>								
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	45,652	111,677	-	-	-	114,262	271,591
33	Fuel Loss Rate	Att to Sch 5A, Line 43 of Page 2	4.49%	4.49%				4.49%	4.49%
34	Delivered Volume	Line 32 times (1 - Line 33)	43,603	106,662	-	-	-	109,132	259,397
35	Variable Transportation Rate	Att to Sch 5A, Line 26 of Page 2	$ 0.3532	$ 0.3532				$ 0.3532	$ 0.3532
36	Variable Transportation Costs	Line 34 times Line 35	$ 15,400	$ 37,673	$ -	$ -	$ -	$ 38,545	$ 91,619
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	43,603	106,662	-	-	-	109,132	259,397
43	Fuel Loss Rate	Att to Sch 5A, Line 39 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)	43,450	106,289	-	-	-	108,750	258,489
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 78	$ 191	$ -	$ -	$ -	$ 196	$ 465

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 32	13,117	-	-	-	-	65,056	78,173
2	City Gate Delivered Volume	Line 44	12,555	-	-	-	-	62,267	74,822
3	Total Purchase Price	Line 24	$ 3.678					$ 3.821	$ 3.797
4	Total Purchase Cost	Line 2 times Line 3	$ 48,245	$ -	$ -	$ -	$ -	$ 248,578	$ 296,824
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 3,901	$ -	$ -	$ -	$ -	$ 19,345	$ 23,246
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 52,146	$ -	$ -	$ -	$ -	$ 267,924	$ 320,069
7	Average Delivered Price	Line 6 divided by Line 2	$ 4.153					$ 4.303	$ 4.278
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	$ 3.678					$ 3.821	$ 3.797
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 L Supply Costs								
19	Purchased Volumes	Sendout Optimization	13,117	-	-	-	-	65,056	78,173
20	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.785
21	NYMEX Cost	Line 9 times Line 10	$ 48,088	$ -	$ -	$ -	$ -	$ 247,798	$ 295,885
22	NYMEX Basis Price	Att to Sch 5A, Line 8 of Page 1	$ 0.012					$ 0.012	$ 0.012
23	NYMEX Basis Costs	Line 9 times Line 12	$ 157	$ -	$ -	$ -	$ -	$ 781	$ 938
24	Total Purchase Price	Line 10 plus Line 12	$ 3.678					$ 3.821	$ 3.797
25	Total Purchase Cost	Line 11 plus Line 13	$ 48,245	$ -	$ -	$ -	$ -	$ 248,578	$ 296,824
26									
27	Transportation Fuel Losses and Variable Charges								
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	13,117	-	-	-	-	65,056	78,173
33	Fuel Loss Rate	Att to Sch 5A, Line 45 of Page 2	3.95%					3.95%	3.95%
34	Delivered Volume	Line 32 times (1 - Line 33)	12,599	-	-	-	-	62,486	75,085
35	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2	$ 0.3078					$ 0.3078	$ 0.3078
36	Variable Transportation Costs	Line 34 times Line 35	$ 3,878	$ -	$ -	$ -	$ -	$ 19,233	$ 23,111
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	12,599	-	-	-	-	62,486	75,085
43	Fuel Loss Rate	Att to Sch 5A, Line 39 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)	12,555	-	-	-	-	62,267	74,822
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 23	$ -	$ -	$ -	$ -	$ 112	$ 135
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 44 of Page 2							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Tennessee Zone 4 200 Leg Pool
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	96,159	150,586	156,425	141,932	134,287	149,418	828,807
2	City Gate Delivered Volume	Line 34	94,500	147,988	153,727	139,483	131,970	146,840	814,509
3	Total Purchase Cost	Line 15	$ 350,596	$ 573,732	$ 608,808	$ 552,399	$ 517,945	$ 569,132	$ 3,172,612
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 11,436	$ 17,909	$ 18,604	$ 16,880	$ 15,971	$ 17,770	$ 98,570
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 362,032	$ 591,641	$ 627,411	$ 569,279	$ 533,916	$ 586,902	$ 3,271,182
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.831	$ 3.998	$ 4.081	$ 4.081	$ 4.046	$ 3.997	$ 4.016
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	96,159	150,586	156,425	141,932	134,287	149,418	828,807
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.844
11	NYMEX Cost	Line 9 times Line 10	$ 352,519	$ 576,744	$ 611,936	$ 555,238	$ 520,631	$ 569,132	$ 3,186,200
12	NYMEX Basis Price	Att to Sch 5A, Line 9 of Page 1	$ (0.020)	$ (0.020)	$ (0.020)	$ (0.020)	$ (0.020)	$ -	$ (0.016)
13	NYMEX Basis Costs	Line 9 times Line 12	$ (1,923)	$ (3,012)	$ (3,129)	$ (2,839)	$ (2,686)	$ -	$ (13,588)
14	Total Purchase Price	Line 10 plus Line 12	$ 3.646	$ 3.810	$ 3.892	$ 3.892	$ 3.857	$ 3.809	$ 3.828
15	Total Purchase Cost	Line 11 plus Line 13	$ 350,596	$ 573,732	$ 608,808	$ 552,399	$ 517,945	$ 569,132	$ 3,172,612
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5083)								
20	Receipt Point: Tennessee Zone 4 200 Leg Pool								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	96,159	150,586	156,425	141,932	134,287	149,418	828,807
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	94,832	148,508	154,267	139,973	132,434	147,356	817,370
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188
26	Variable Transportation Costs	Line 24 times Line 25	$ 11,266	$ 17,643	$ 18,327	$ 16,629	$ 15,733	$ 17,506	$ 97,104
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	94,832	148,508	154,267	139,973	132,434	147,356	817,370
33	Fuel Loss Rate	Att to Sch 5A, Line 39 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)	94,500	147,988	153,727	139,483	131,970	146,840	814,509
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 170	$ 266	$ 277	$ 251	$ 238	$ 264	$ 1,466

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-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	179,334	189,699	189,699	171,341	189,699	-	919,772
2	City Gate Delivered Volume	Sum Lines 64, 84 and 104	170,113	179,674	179,674	162,286	179,746	-	871,493
3	Total Purchase Cost	Line 15	$ 691,333	$ 762,400	$ 777,955	$ 702,669	$ 771,316	$ -	$ 3,705,674
4	Variable Transportation Costs	Sum Lines 26, 46, 56, 66, 76, 86, 96 and 106	$ 16,762	$ 17,736	$ 17,736	$ 16,020	$ 17,724	$ -	$ 85,979
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 708,095	$ 780,136	$ 795,692	$ 718,689	$ 789,040	$ -	$ 3,791,653
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.163	$ 4.342	$ 4.429	$ 4.429	$ 4.390		$ 4.351
7									
8	<u>Chicago Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	179,334	189,699	189,699	171,341	189,699	-	919,772
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.840
11	NYMEX Cost	Line 9 times Line 10	$ 657,439	$ 726,547	$ 742,102	$ 670,286	$ 735,463	$ -	$ 3,531,837
12	NYMEX Basis Price	Att to Sch 5A, Line 1 of Page 1	$ 0.189	$ 0.189	$ 0.189	$ 0.189	$ 0.189		$ 0.189
13	NYMEX Basis Costs	Line 9 times Line 12	$ 33,894	$ 35,853	$ 35,853	$ 32,383	$ 35,853	$ -	$ 173,837
14	Total Purchase Price	Line 10 plus Line 12	$ 3.855	$ 4.019	$ 4.101	$ 4.101	$ 4.066		$ 4.029
15	Total Purchase Cost	Line 11 plus Line 13	$ 691,333	$ 762,400	$ 777,955	$ 702,669	$ 771,316	$ -	$ 3,705,674
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
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	179,334	189,699	189,699	171,341	189,699	-	919,772
23	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	0.93%	0.93%	0.93%	0.93%	0.93%		0.93%
24	Delivered Volume	Line 22 times (1 - Line 23)	177,666	187,935	187,935	169,748	187,935	-	911,218
25	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 320	$ 338	$ 338	$ 306	$ 338	$ -	$ 1,640
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 24	177,666	187,935	187,935	169,748	187,935	-	911,218
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.98%	0.98%	0.98%	0.98%	0.98%		0.98%
34	Delivered Volume	Line 32 times (1 - Line 33)	175,925	186,093	186,093	168,084	186,093	-	902,288
35	Variable Transportation Rate	Att to Sch 5A, Line 33 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 34	175,925	186,093	186,093	168,084	186,093	-	902,288
43	Fuel Loss Rate	Att to Sch 5A, Line 49 of Page 2	1.38%	1.38%	1.38%	1.38%	1.38%		1.38%
44	Delivered Volume	Line 42 times (1 - Line 43)	173,497	183,525	183,525	165,764	183,525	-	889,837
45	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2	$ -	$ -	$ -	$ -	$ -		$ -
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	173,497	183,525	183,525	165,764	183,525	-	889,837
53	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.20%	0.20%	0.20%	0.20%	0.20%		0.20%
54	Delivered Volume	Line 52 times (1 - Line 53)	173,150	183,158	183,158	165,433	183,158	-	888,057
55	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048		$ 0.0048
56	Variable Transportation Costs	Line 54 times Line 55	$ 831	$ 879	$ 879	$ 794	$ 879	$ -	$ 4,263
57			$ 911	$ 975	$ 975	$ 880	$ 943	$ -	
58	Transporation Segment 6A								
59	Tennessee Gas Pipeline (Contract 95196)								
60	Receipt Point: Wright								
61	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
62	Received Volume	Line 54	25,221	23,402	23,402	21,137	30,067	-	123,228
63	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%		1.06%
64	City Gate Delivered Volume	Line 62 times (1 - Line 63)	24,954	23,154	23,154	20,913	29,748	-	121,922
65	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896		$ 0.0896
66	Variable Transportation Costs	Line 64 times Line 65	$ 2,236	$ 2,075	$ 2,075	$ 1,874	$ 2,665	$ -	$ 10,924
67			$ 3,715	$ 3,839	$ 3,839	$ 3,467	$ 3,839	$ -	
68	Transportation Segment 6B								
69	Tennessee Gas Pipeline (Contract 95196)								
70	Receipt Point: Wright								
71	Delivery Point: Pleasant St. (Interconnection with Granite)								
72	Received Volume	Line 64	25,591	26,444	26,444	23,885	26,444	-	128,809
73	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%		1.06%
74	Delivered Volume	Line 72 times (1 - Line 73)	25,320	26,164	26,164	23,632	26,164	-	127,444
75	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896		$ 0.0896
76	Variable Transportation Costs	Line 74 times Line 75	$ 2,269	$ 2,344	$ 2,344	$ 2,117	$ 2,344	$ -	$ 11,419
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	25,320	26,164	26,164	23,632	26,164	-	127,444
83	Fuel Loss Rate	Att to Sch 5A, Line 39 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)	25,231	26,072	26,072	23,549	26,072	-	126,998
85	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
86	Variable Transportation Costs	Line 84 times Line 85	$ 45	$ 47	$ 47	$ 42	$ 47	$ -	$ 229
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	122,338	133,312	133,312	120,411	126,646	-	636,020
93	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%		1.06%
94	Delivered Volume	Line 92 times (1 - Line 93)	121,042	131,899	131,899	119,134	125,304	-	629,278
95	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896		$ 0.0896
96	Variable Transportation Costs	Line 94 times Line 95	$ 10,845	$ 11,818	$ 11,818	$ 10,674	$ 11,227	$ -	$ 56,383
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	121,042	131,899	131,899	119,134	125,304	-	629,278
103	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2	0.92%	1.10%	1.10%	1.10%	1.10%		1.07%
104	City Gate Delivered Volume	Line 102 times (1 - Line 103)	119,928	130,448	130,448	117,824	123,926	-	622,574
105	Variable Transportation Rate	Att to Sch 5A, Line 19 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
106	Variable Transportation Costs	Line 104 times Line 105	$ 216	$ 235	$ 235	$ 212	$ 223	$ -	$ 1,121

Source of Supply: Algonquin Receipts
Delivered to Northern via Algonquin Pipeline and Bay State Exchange

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	37,878	39,212	39,212	35,418	39,212	-	190,933
2	City Gate Delivered Volume	Sum Lines 24	37,530	38,781	38,781	35,028	38,781	-	188,901
3	Total Purchase Cost	Line 15	$ 147,915	$ 181,318	$ 186,180	$ 163,842	$ 162,339	$ -	$ 841,594
4	Variable Transportation Costs	Sum Lines 26	$ 488	$ 504	$ 504	$ 455	$ 504	$ -	$ 2,456
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 148,403	$ 181,822	$ 186,684	$ 164,297	$ 162,843	$ -	$ 844,050
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.954	$ 4.688	$ 4.814	$ 4.690	$ 4.199		$ 4.468
7									
8	<u>Algonquin Receipts Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	37,878	39,212	39,212	35,418	39,212	-	190,933
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.839
11	NYMEX Cost	Line 9 times Line 10	$ 138,863	$ 150,183	$ 153,399	$ 138,554	$ 152,026	$ -	$ 733,024
12	NYMEX Basis Price	Att to Sch 5A, Line 19 of Page 1	$ 0.239	$ 0.794	$ 0.836	$ 0.714	$ 0.263		$ 0.569
13	NYMEX Basis Costs	Line 9 times Line 12	$ 9,053	$ 31,135	$ 32,782	$ 25,288	$ 10,313	$ -	$ 108,570
14	Total Purchase Price	Line 10 plus Line 12	$ 3.905	$ 4.624	$ 4.748	$ 4.626	$ 4.140		$ 4.408
15	Total Purchase Cost	Line 11 plus Line 13	$ 147,915	$ 181,318	$ 186,180	$ 163,842	$ 162,339	$ -	$ 841,594
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Algonquin Pipeline (Contract 93201A1C)								
20	Receipt Point: Algonquin Receipt Points								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 15	37,878	39,212	39,212	35,418	39,212	-	190,933
23	Fuel Loss Rate	Att to Sch 5A, Line 38 of Page 2	0.92%	1.10%	1.10%	1.10%	1.10%		1.20%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	37,530	38,781	38,781	35,028	38,781	-	188,901
25	Variable Transportation Rate	Att to Sch 5A, Line 20 of Page 2	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130		$ 0.0130
26	Variable Transportation Costs	Line 24 times Line 25	$ 488	$ 504	$ 504	$ 455	$ 504	$ -	$ 2,456

Source of Supply: Tennessee Gas Pipeline Zone 6 Baseload Supply
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	57,094	57,094
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	56,894	56,894
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ 252,584	$ 252,584
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ 102	$ 102
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ 252,686	$ 252,686
6	Average Delivered Price	Line 5 divided by Line 2						$ 4.441	$ 4.441
7									
8	<u>Tennessee Zone 6 Supply</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	57,094	57,094
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.809
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 217,471	$ 217,471
12	NYMEX Basis Price	Att to Sch 5A, Line 18 of Page 1						$ 0.615	$ 0.615
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 35,113	$ 35,113
14	Total Purchase Price	Line 10 plus Line 12						$ 4.424	$ 4.424
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ 252,584	$ 252,584
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	-	-	-	-	-	57,094	57,094
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	56,894	56,894
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ 102	$ 102

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-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	59,149	64,337	64,337	58,111	61,120	45,088	352,143
2	City Gate Delivered Volume	Line 44	58,317	63,433	63,433	57,294	60,261	44,454	347,191
3	Total Purchase Cost	Line 15	$ 255,464	$ 288,424	$ 293,700	$ 265,277	$ 276,876	$ 187,521	$ 1,567,262
4	Variable Transportation Costs	Sum Lines 26, 36 and 46	$ 5,349	$ 5,818	$ 5,818	$ 5,255	$ 5,527	$ 4,077	$ 31,843
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 260,812	$ 294,242	$ 299,518	$ 270,532	$ 282,403	$ 191,598	$ 1,599,104
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.472	$ 4.639	$ 4.722	$ 4.722	$ 4.686	$ 4.310	$ 4.606
7									
8	<u>Niagara Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	59,149	64,337	64,337	58,111	61,120	45,088	352,143
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.836
11	NYMEX Cost	Line 9 times Line 10	$ 216,840	$ 246,412	$ 251,688	$ 227,331	$ 236,964	$ 171,740	$ 1,350,974
12	NYMEX Basis Price	Att to Sch 5A, Line 6 of Page 1	$ 0.653	$ 0.653	$ 0.653	$ 0.653	$ 0.653	$ 0.350	$ 0.614
13	NYMEX Basis Costs	Line 9 times Line 12	$ 38,624	$ 42,012	$ 42,012	$ 37,947	$ 39,912	$ 15,781	$ 216,288
14	Total Purchase Price	Line 10 plus Line 12	$ 4.319	$ 4.483	$ 4.565	$ 4.565	$ 4.530	$ 4.159	$ 4.451
15	Total Purchase Cost	Line 11 plus Line 13	$ 255,464	$ 288,424	$ 293,700	$ 265,277	$ 276,876	$ 187,521	$ 1,567,262
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: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 9	35,616	38,740	38,740	34,991	36,803	27,648	212,538
23	Fuel Loss Rate	Att to Sch 5A, Line 47 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)	35,238	38,330	38,330	34,620	36,413	27,355	210,285
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896
26	Variable Transportation Costs	Line 24 times Line 25	$ 3,157	$ 3,434	$ 3,434	$ 3,102	$ 3,263	$ 2,451	$ 18,842
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	23,533	25,597	25,597	23,120	24,317	17,440	139,605
33	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
34	Delivered Volume	Line 32 times (1 - Line 33)	23,283	25,326	25,326	22,875	24,060	17,255	138,125
35	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896
36	Variable Transportation Costs	Line 34 times Line 35	$ 2,086	$ 2,269	$ 2,269	$ 2,050	$ 2,156	$ 1,546	$ 12,376
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	58,522	63,655	63,655	57,495	60,473	44,610	348,410
43	Fuel Loss Rate	Att to Sch 5A, Line 39 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)	58,317	63,433	63,433	57,294	60,261	44,454	347,191
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 105	$ 114	$ 114	$ 103	$ 108	$ 80	$ 625

Source of Supply: Iroquois Receipts (Interconnect of TransCanada and Iroquoios Pipelines)
Delivered to Northern via Iroquois, Tennessee and Granite Pipelines
Delivered to Northern via Iroquois, Tennessee, Algonquin Pipelines and Bay State Exchange Agreement

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	16,717	19,939	19,939	18,010	13,260	-	87,865
2	City Gate Delivered Volume	Line 34	16,506	19,688	19,688	17,783	13,094	-	86,760
3	Total Purchase Cost	Line 15	$ 93,079	$ 114,292	$ 115,927	$ 104,708	$ 76,632	$ -	$ 504,638
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 1,559	$ 1,860	$ 1,860	$ 1,680	$ 1,237	$ -	$ 8,195
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 94,638	$ 116,152	$ 117,787	$ 106,388	$ 77,868	$ -	$ 512,833
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.733	$ 5.899	$ 5.983	$ 5.983	$ 5.947		$ 5.911
7									
8	<u>Irqoquois Receipts Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	16,717	19,939	19,939	18,010	13,260	-	87,865
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.841
11	NYMEX Cost	Line 9 times Line 10	$ 61,284	$ 76,368	$ 78,003	$ 70,454	$ 51,410	$ -	$ 337,518
12	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1	$ 1.902	$ 1.902	$ 1.902	$ 1.902	$ 1.902		$ 1.902
13	NYMEX Basis Costs	Line 9 times Line 12	$ 31,795	$ 37,925	$ 37,925	$ 34,254	$ 25,221	$ -	$ 167,120
14	Total Purchase Price	Line 10 plus Line 12	$ 5.568	$ 5.732	$ 5.814	$ 5.814	$ 5.779		$ 5.743
15	Total Purchase Cost	Line 11 plus Line 13	$ 93,079	$ 114,292	$ 115,927	$ 104,708	$ 76,632	$ -	$ 504,638
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 5								
19	Iroquois Pipeline (Contract R181001)								
20	Receipt Point: Waddington								
21	Delivery Point: Wright (Interconnection with Tennessee)								
22	Received Volume	Line 9	16,717	19,939	19,939	18,010	13,260	-	87,865
23	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	16,683	19,899	19,899	17,974	13,234	-	87,690
25	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048
26	Variable Transportation Costs	Line 24 times Line 25	$ 80	$ 96	$ 96	$ 86	$ 64	$ -	$ 421
27									
28	Transporation Segment 6A								
29	Tennessee Gas Pipeline (Contract 95196)								
30	Receipt Point: Wright								
31	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
32	Received Volume	Line 24	16,683	19,899	19,899	17,974	13,234	-	87,690
33	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	16,506	19,688	19,688	17,783	13,094	-	86,760
35	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896
36	Variable Transportation Costs	Line 34 times Line 35	$ 1,479	$ 1,764	$ 1,764	$ 1,593	$ 1,173	$ -	$ 7,774

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	27,000	27,900	27,900	25,200	27,900	-	135,900
2	City Gate Delivered Volume	Line 34	26,906	27,802	27,802	25,112	27,802	-	135,424
3	Total Purchase Cost	Line 15	$ 179,982	$ 190,557	$ 192,845	$ 174,182	$ 191,868	$ -	$ 929,434
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 97	$ 100	$ 100	$ 91	$ 100	$ -	$ 488
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 180,079	$ 190,657	$ 192,945	$ 174,273	$ 191,969	$ -	$ 929,923
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.693	$ 6.858	$ 6.940	$ 6.940	$ 6.905		$ 6.867
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	27,000	27,900	27,900	25,200	27,900	-	135,900
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.839
11	NYMEX Cost	Line 9 times Line 10	$ 98,982	$ 106,857	$ 109,145	$ 98,582	$ 108,168	$ -	$ 521,734
12	NYMEX Basis Price	Att to Sch 5A, Line 4 of Page 1	$ 3.000	$ 3.000	$ 3.000	$ 3.000	$ 3.000		$ 3.000
13	NYMEX Basis Costs	Line 9 times Line 12	$ 81,000	$ 83,700	$ 83,700	$ 75,600	$ 83,700	$ -	$ 407,700
14	Total Purchase Price	Line 10 plus Line 12	$ 6.666	$ 6.830	$ 6.912	$ 6.912	$ 6.877		$ 6.839
15	Total Purchase Cost	Line 11 plus Line 13	$ 179,982	$ 190,557	$ 192,845	$ 174,182	$ 191,868	$ -	$ 929,434
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
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	27,000	27,900	27,900	25,200	27,900	-	135,900
23	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	27,000	27,900	27,900	25,200	27,900	-	135,900
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 49	$ 50	$ 50	$ 45	$ 50	$ -	$ 245
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	27,000	27,900	27,900	25,200	27,900	-	135,900
33	Fuel Loss Rate	Att to Sch 5A, Line 39 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)	26,906	27,802	27,802	25,112	27,802	-	135,424
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 48	$ 50	$ 50	$ 45	$ 50	$ -	$ 244

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

			2013-2014 Peak	2013-2014 Peak	2013-2014 Peak	2013-2014 Peak	2013-2014 Peak	2013-2014 Peak	
Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	27,000	27,900	27,900	25,200	27,900	-	135,900
2	City Gate Delivered Volume	Line 24	26,906	27,802	27,802	25,112	27,802	-	135,424
3	Total Purchase Cost	Line 15	$ 213,732	$ 225,432	$ 227,720	$ 205,682	$ 226,743	$ -	$ 1,099,309
4	Variable Transportation Costs	Line 26	$ 48	$ 50	$ 50	$ 45	$ 50	$ -	$ 244
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 213,780	$ 225,482	$ 227,770	$ 205,728	$ 226,793	$ -	$ 1,099,553
6	Average Delivered Price	Line 5 divided by Line 2	$ 7.946	$ 8.110	$ 8.192	$ 8.192	$ 8.157		$ 8.119
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	27,000	27,900	27,900	25,200	27,900	-	135,900
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.839
11	NYMEX Cost	Line 9 times Line 10	$ 98,982	$ 106,857	$ 109,145	$ 98,582	$ 108,168	$ -	$ 521,734
12	NYMEX Basis Price	Att to Sch 5A, Line 3 of Page 1	$ 4.250	$ 4.250	$ 4.250	$ 4.250	$ 4.250		$ 4.250
13	NYMEX Basis Costs	Line 9 times Line 12	$ 114,750	$ 118,575	$ 118,575	$ 107,100	$ 118,575	$ -	$ 577,575
14	Total Purchase Price	Line 10 plus Line 12	$ 7.916	$ 8.080	$ 8.162	$ 8.162	$ 8.127		$ 8.089
15	Total Purchase Cost	Line 11 plus Line 13	$ 213,732	$ 225,432	$ 227,720	$ 205,682	$ 226,743	$ -	$ 1,099,309
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: Granite (Westbrook)								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	27,000	27,900	27,900	25,200	27,900	-	135,900
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	26,906	27,802	27,802	25,112	27,802	-	135,424
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 48	$ 50	$ 50	$ 45	$ 50	$ -	$ 244

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	195,000	201,500	201,500	182,000	201,500	45,000	1,026,500
2	City Gate Delivered Volume	Line 1	195,000	201,500	201,500	182,000	201,500	45,000	1,026,500
3	Total Purchase Cost	Line 15	$ 1,670,370	$ 1,759,095	$ 1,775,618	$ 1,603,784	$ 1,768,565	$ 199,080	$ 8,776,512
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 1,670,370	$ 1,759,095	$ 1,775,618	$ 1,603,784	$ 1,768,565	$ 199,080	$ 8,776,512
6	Average Delivered Price	Line 5 divided by Line 2	$ 8.566	$ 8.730	$ 8.812	$ 8.812	$ 8.777	$ 4.424	$ 8.550
7									
8	<u>Lewiston Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	195,000	201,500	201,500	182,000	201,500	45,000	1,026,500
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.838
11	NYMEX Cost	Line 9 times Line 10	$ 714,870	$ 771,745	$ 788,268	$ 711,984	$ 781,216	$ 171,405	$ 3,939,488
12	NYMEX Basis Price	Att to Sch 5A, Line 5 of Page 1	$ 4.900	$ 4.900	$ 4.900	$ 4.900	$ 4.900	$ 0.615	$ 4.712
13	NYMEX Basis Costs	Line 9 times Line 12	$ 955,500	$ 987,350	$ 987,350	$ 891,800	$ 987,350	$ 27,675	$ 4,837,025
14	Total Purchase Price	Line 10 plus Line 12	$ 8.566	$ 8.730	$ 8.812	$ 8.812	$ 8.777	$ 4.424	$ 8.550
15	Total Purchase Cost	Line 11 plus Line 13	$ 1,670,370	$ 1,759,095	$ 1,775,618	$ 1,603,784	$ 1,768,565	$ 199,080	$ 8,776,512

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Gross Withdrawn Volume	Line 9	-	-	74,946	67,693	54,198	-	196,837
2	City Gate Delivered Volume	Line 35	-	-	73,653	66,525	53,263	-	193,442
3	Total Withdrawal Costs	Line 16	$ -	$ -	$ 280,276	$ 253,152	$ 202,683	$ -	$ 736,110
4	Variable Transportation Costs	Sum Lines 27 and 37	$ -	$ -	$ 8,913	$ 8,051	$ 6,446	$ -	$ 23,410
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ 289,189	$ 261,203	$ 209,128	$ -	$ 759,520
6	Average Delivered Price	Line 5 divided by Line 2			$ 3.926	$ 3.926	$ 3.926		$ 3.926
7									
8	<u>Tennessee FS-MA Withdrawn Inventory (Segment 1)</u>								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	74,946	67,693	54,198	-	196,837
10	Withdrawal Rate	Att to Sch 5A, Line 1 of Page 3			$ 0.0087	$ 0.0087	$ 0.0087		$ 0.0087
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ 652	$ 589	$ 472	$ -	$ 1,712
12	Inventory Rate	FXW-8			$ 3.7310	$ 3.7310	$ 3.7310		$ 3.7310
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ 279,624	$ 252,563	$ 202,211	$ -	$ 734,398
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 1 of Page 3 times Line	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	-	-	74,946	67,693	54,198	-	196,837
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ 280,276	$ 253,152	$ 202,683	$ -	$ 736,110
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 2								
20	Tennessee Gas Pipeline (Contract 5265)								
21	Receipt Point: Tennessee FS-MA Withdrawal Meter								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 16	-	-	74,946	67,693	54,198	-	196,837
24	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2			1.38%	1.38%	1.38%		1.38%
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	73,912	66,759	53,450	-	194,121
26	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2			$ 0.1188	$ 0.1188	$ 0.1188		$ 0.1188
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ 8,781	$ 7,931	$ 6,350	$ -	$ 23,062
28									
29	Transportation Segment 3								
30	Granite State Gas Transmission (Contract 10-010-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	-	-	73,912	66,759	53,450	-	194,121
34	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	-	-	73,653	66,525	53,263	-	193,442
36	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ 133	$ 120	$ 96	$ -	$ 348

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

	Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2013-2014 Peak	2014 Off-Peak	2014-2015 Peak
	1	Gross Withdrawn Volume	Line 9	81,189	524,903	884,815	740,813	383,517	-	-	-	-	-	-	-	150,940	702,066	1,003,912	885,863	480,420	-	2,615,238	-	3,223,200
	2	City Gate Delivered Volume	Line 65	79,127	511,569	862,338	721,994	373,774	-	-	-	-	-	-	-	147,106	684,231	978,410	863,359	468,215	-	2,548,803	-	3,141,321
	3	Total Withdrawal Costs	Line 16	$ 313,959	$ 2,029,801	$ 3,421,581	$ 2,864,725	$ 1,483,060	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 591,723	$ 2,752,268	$ 3,935,578	$ 3,472,797	$ 1,883,364	$ -	$ 10,113,127	$ -	$ 12,635,730
	4	Variable Transportation Costs	Sum Lines 27, 37, 47, 57 and 67	$ 430	$ 2,783	$ 4,691	$ 3,928	$ 2,033	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 800	$ 3,722	$ 5,323	$ 4,697	$ 2,547	$ -	$ 13,865	$ -	$ 17,089
	5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 314,389	$ 2,032,584	$ 3,426,273	$ 2,868,653	$ 1,485,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 592,523	$ 2,755,991	$ 3,940,901	$ 3,477,494	$ 1,885,911	$ -	$ 10,126,992	$ -	$ 12,652,819
	6	Average Delivered Price	Line 5 divided by Line 2	$ 3.973	$ 3.973	$ 3.973	$ 3.973	$ 3.973								$ 4.028	$ 4.028	$ 4.028	$ 4.028	$ 4.028		$ 3.973		$ 4.028
	7																							
	8	Washington 10 Withdrawn Inventory (Segment 1)																						
W-10	9	Gross Withdrawn Volume	Sendout Optimization	81,189	524,903	884,815	740,813	383,517	-	-	-	-	-	-	-	150,940	702,066	1,003,912	885,863	480,420	-	2,615,238	-	3,223,200
W-10	10	Withdrawal Rate	Att to Sch 5A, Line 3 of Page 3	$ -	$ -	$ -	$ -	$ -								$ -	$ -	$ -	$ -	$ -		$ -		$ -
W-10	11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W-10	12	Inventory Rate	FXW-8	$ 3.8670	$ 3.8670	$ 3.8670	$ 3.8670	$ 3.8670								$ 3.9202	$ 3.9202	$ 3.9202	$ 3.9202	$ 3.9202		$ 3.8670		$ 3.9202
W-10	13	Withdrawn Inventory Value	Line 9 times Line 12	$ 313,959	$ 2,029,801	$ 3,421,581	$ 2,864,725	$ 1,483,060	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 591,723	$ 2,752,268	$ 3,935,578	$ 3,472,797	$ 1,883,364	$ -	$ 10,113,127	$ -	$ 12,635,730
W-10	14	Withdrawal Fuel Losses	Att to Sch 5A, Line 3 of Page 3 times Line	325	2,100	3,539	2,963	1,534	-	-	-	-	-	-	-	604	2,808	4,016	3,543	1,922	-	10,461	-	12,893
W-10	15	Net Withdrawn Volume	Line 9 minus Line 14	80,864	522,804	881,276	737,850	381,983	-	-	-	-	-	-	-	150,336	699,257	999,896	882,319	478,498	-	2,604,777	-	3,210,307
W-10	16	Total Withdrawal Costs	Line 11 plus Line 13	$ 313,959	$ 2,029,801	$ 3,421,581	$ 2,864,725	$ 1,483,060	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 591,723	$ 2,752,268	$ 3,935,578	$ 3,472,797	$ 1,883,364	$ -	$ 10,113,127	$ -	$ 12,635,730
	17																							
	18	Transportation Fuel Losses and Variable Charges																						
	19	Transportation Segment 2A																						
	20	Vector Pipeline (Contract CRL-NUI-0725)																						
	21	Receipt Point: Washington 10 Withdrawal Meter																						
	22	Delivery Point: Dawn (Interconnects with TransCanada)																						
P13 VECTOR3	23	Received Volume	Line 15	47,685	243,088	392,894	365,703	199,821	-	-	-	-	-	-	-	104,779	339,738	494,626	438,895	252,316	-	1,249,192	-	1,630,353
P13 VECTOR3	24	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2	0.32%	0.32%	0.32%	0.32%	0.32%								0.32%	0.32%	0.32%	0.32%	0.32%		0.32%		0.32%
P13 VECTOR3	25	Delivered Volume	Line 23 times (1 - Line 24)	47,532	242,311	391,637	364,533	199,182	-	-	-	-	-	-	-	104,443	338,651	493,043	437,490	251,509	-	1,245,194	-	1,625,136
P13 VECTOR3	26	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018								$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018		$ 0.0018
P13 VECTOR3	27	Variable Transportation Costs	Line 25 times Line 26	$ 86	$ 436	$ 705	$ 656	$ 359	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 188	$ 610	$ 887	$ 787	$ 453	$ -	$ 2,241	$ -	$ 2,925
	28																							
	29	Transportation Segment 2B																						
	30	Vector Pipeline (Contract CRL-NUI-0727)																						
	31	Receipt Point: Washington 10 Withdrawal Meter																						
	32	Delivery Point: Union Dawn (Interconnects with TransCanada)																						
P13VECT2WS	33	Received Volume	Line 25	33,180	279,715	488,382	372,147	182,162	-	-	-	-	-	-	-	45,558	359,519	505,270	443,425	226,182	-	1,355,586	-	1,579,954
P13VECT2WS	34	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2	0.32%	0.32%	0.32%	0.32%	0.32%								0.32%	0.32%	0.32%	0.32%	0.32%		0.32%		0.32%
P13VECT2WS	35	Delivered Volume	Line 33 times (1 - Line 34)	33,074	278,820	486,819	370,956	181,579	-	-	-	-	-	-	-	45,412	358,369	503,653	442,006	225,458	-	1,351,248	-	1,574,898
P13VECT2WS	36	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018								$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018		$ 0.0018
P13VECT2WS	37	Variable Transportation Costs	Line 35 times Line 36	$ 60	$ 502	$ 876	$ 668	$ 327	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 82	$ 645	$ 907	$ 796	$ 406	$ -	$ 2,432	$ -	$ 2,835
	38																							
	39	Transportation Segment 3																						
	40	TransCanada Pipeline (Contract 33322)																						
	41	Receipt Point: Union Dawn																						
	42	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)																						
P13 TCPL	43	Received Volume	Line 35	80,606	521,131	878,456	735,489	380,761	-	-	-	-	-	-	-	149,855	697,020	996,696	879,496	476,967	-	2,596,442	-	3,200,034
P13 TCPL	44	Fuel Loss Rate	Att to Sch 5A, Line 48 of Page 2	1.49%	1.49%	1.49%	1.49%	1.49%								1.49%	1.49%	1.49%	1.49%	1.49%		1.49%		1.49%
P13 TCPL	45	Delivered Volume	Line 43 times (1 - Line 44)	79,405	513,366	865,367	724,530	375,087	-	-	-	-	-	-	-	147,623	686,634	981,846	866,391	469,860	-	2,557,755	-	3,152,354
P13 TCPL	46	Variable Transportation Rate	Att to Sch 5A, Line 31 of Page 2	$ -	$ -	$ -	$ -	$ -								$ -	$ -	$ -	$ -	$ -		$ -		$ -
P13 TCPL	47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	48																							
	49	Transportation Segment 4																						
	50	PNGTS (Contract 1997-004)																						
	51	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)																						
	52	Delivery Point: Granite (Westbrook, Newington, Eliot)																						
P13 PNGTS WS	53	Received Volume	Line 45	79,405	513,366	865,367	724,530	375,087	-	-	-	-	-	-	-	147,623	686,634	981,846	866,391	469,860	-	2,557,755	-	3,152,354
P13 PNGTS WS	54	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%								0.00%	0.00%	0.00%	0.00%	0.00%		0.00%		0.00%
P13 PNGTS WS	55	Delivered Volume	Line 53 times (1 - Line 54)	79,405	513,366	865,367	724,530	375,087	-	-	-	-	-	-	-	147,623	686,634	981,846	866,391	469,860	-	2,557,755	-	3,152,354
P13 PNGTS WS	56	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018								$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018		$ 0.0018
P13 PNGTS WS	57	Variable Transportation Costs	Line 55 times Line 56	$ 143	$ 924	$ 1,558	$ 1,304	$ 675	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 266	$ 1,236	$ 1,767	$ 1,560	$ 846	$ -	$ 4,604	$ -	$ 5,674
	58																							
	59	Transportation Segment 5																						
	60	Granite State Gas Transmission (Contract 10-010-FT-NN)																						
	61	Receipt Point: Westbrook, Newington, Eliot																						
	62	Delivery Point: Northern City Gates																						
GSGT FLOW	63	Received Volume	Line 55	79,405	513,366	865,367	724,530	375,087	-	-	-	-	-	-	-	147,623	686,634	981,846	866,391	469,860	-	2,557,755	-	3,152,354
GSGT FLOW	64	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%		0.35%
GSGT FLOW	65	City Gate Delivered Volume	Line 63 times (1 - Line 64)	79,127	511,569	862,338	721,994	373,774	-	-	-	-	-	-	-	147,106	684,231	978,410	863,359	468,215	-	2,548,803	-	3,141,321
GSGT FLOW	66	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
GSGT FLOW	67	Variable Transportation Costs	Line 65 times Line 66	$ 142	$ 921	$ 1,552	$ 1,300	$ 673	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 265	$ 1,232	$ 1,761	$ 1,554	$ 843	$ -	$ 4,588	$ -	$ 5,654

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

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 11 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 39 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 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
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-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 2 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 12 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 39 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 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
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-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Purchased Volumes	Line 9	-	-	156,027	93,973	-	-	250,000
2	City Gate Delivered Volume	Line 24	-	-	155,481	93,644	-	-	249,125
3	Total Purchase Cost	Line 15	$ -	$ -	$ 2,519,339	$ 1,517,361	$ -	$ -	$ 4,036,700
4	Variable Transportation Costs	Line 26	$ -	$ -	$ 280	$ 169	$ -	$ -	$ 448
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ 2,519,619	$ 1,517,530	$ -	$ -	$ 4,037,149
6	Average Delivered Price	Line 5 divided by Line 2			$ 16.205	$ 16.205			$ 16.205
7									
8	<u>Peaking Supply 3 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	156,027	93,973	-	-	250,000
10	Monthly Commodity Price	Att to Sch 5A, Line 21 of Page 1	$ 16.147	$ 16.147	$ 16.147	$ 16.147	$ 16.147	$ 16.147	$ 16.147
11	Commodity Cost	Line 9 times Line 10	$ -	$ -	$ 2,519,339	$ 1,517,361	$ -	$ -	$ 4,036,700
12	Basis Price	Att to Sch 5A, Line 13 of Page 1			$ -	$ -			$ -
13	Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12			$ 16.147	$ 16.147			$ 16.147
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ 2,519,339	$ 1,517,361	$ -	$ -	$ 4,036,700
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	-	-	156,027	93,973	-	-	250,000
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	155,481	93,644	-	-	249,125
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ 280	$ 169	$ -	$ -	$ 448

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	2013-2014 Peak
1	Gross Withdrawn Volume	Line 9	1,350	1,395	1,395	1,260	1,395	3,065	9,860
2	City Gate Delivered Volume	Line 15	1,350	1,395	1,395	1,260	1,395	3,065	9,860
3	Total Withdrawal Costs	Line 16	$ 9,135	$ 9,824	$ 9,902	$ 9,434	$ 10,357	$ 21,201	$ 69,852
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 9,135	$ 9,824	$ 9,902	$ 9,434	$ 10,357	$ 21,201	$ 69,852
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.766	$ 7.042	$ 7.098	$ 7.487	$ 7.424	$ 6.917	$ 7.084
7									
8	<u>Northern LNG Withdrawn Inventory</u>								
9	Gross Withdrawn Volume	Sendout Optimization	1,350	1,395	1,395	1,260	1,395	3,065	9,860
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8	$ 6.7664	$ 7.0424	$ 7.0979	$ 7.4874	$ 7.4245	$ 6.9170	$ 7.0844
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 9,135	$ 9,824	$ 9,902	$ 9,434	$ 10,357	$ 21,201	$ 69,852
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	1,350	1,395	1,395	1,260	1,395	3,065	9,860
16	Total Withdrawal Costs	Line 11 plus Line 13	$ 9,135	$ 9,824	$ 9,902	$ 9,434	$ 10,357	$ 21,201	$ 69,852

Schedule 7

Northern Utilities, Inc.
Hedging Gains and Losses
November 2013 through April 2014
As of 9/5/2013

Description	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Winter
NYMEX Contracts	19	28	32	28	25	15	147
Average Purchase Price	$ 3.844	$ 4.048	$ 4.132	$ 4.139	$ 4.064	$ 3.955	$ 4.051
Current NYMEX Price	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809	$ 3.848
Hedging (Gains) and Losses	$ 33,780	$ 61,100	$ 70,540	$ 63,680	$ 46,770	$ 21,860	$ 297,730

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 743 therms/year

Comparison of Winter 2013-2014 vs. Winter 2012-2013

1				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
2		Typical Usage: therms		43	95	131	141	117	82	609	39	23	17	15	16	23	134	743
3	**Winter 2013 - 2014**																	
4	Customer Charge	units @	$ 13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38								
5	First	50 units @	$0.4831	$20.53	$24.16	$24.16	$24.16	$24.16	$24.16	$141.31								
6	Over	50 units @	$0.4250	$0.00	$18.93	$34.48	$38.85	$28.39	$13.70	$134.34								
7		COG 1	$0.8567	$36.41						$36.41								
8		COG 2	$0.8567		$80.99					$80.99								
9		COG 3	$0.8567			$112.33				$112.33								
10		COG 4	$0.8567				$121.14			$121.14								
11		COG 5	$0.8567					$100.07		$100.07								
12		COG 6	$0.8567						$70.44	$70.44								
13		LDAC	$0.0446	$1.90	$4.22	$5.85	$6.31	$5.21	$3.67	$27.14								
14	**Summer 2013**																	
15	Customer Charge	units @	$ 13.73								$ 13.73	$13.73	$13.73	$13.73	$ 13.73	$13.73	$82.38	
16	First	50 units @	$0.4410								$17.30	$10.36					$27.65	
17		50 units @ Temp	$0.4831										$8.28	$7.18	$7.79	$11.21	$34.46	
18	Over	50 units @	$0.4410								$0.00	$0.00					$0.00	
19		50 units @ Temp	$0.4831										$0.00	$0.00	$0.00	$0.00	$0.00	
20		COG 1	$0.5553								$21.78						$21.78	
21		COG 2	$0.5858									$13.76					$13.76	
22		COG 3	$0.5858										$10.04				$10.04	
23		COG 4	$0.5858											$8.70			$8.70	
24		COG 5	$0.5858												$9.45		$9.45	
25		COG 6	$0.5858													$13.59	$13.59	
26	Summer Period 2013 Weighted Avg. COG		$0.5769															
27		LDAC	$ 0.0551								$2.16	$1.29	$0.94	$0.82	$0.89	$1.28	$7.39	
28			**TOTAL**	$72.57	$142.01	$190.54	$204.18	$171.56	$125.69	**$906.56**	$54.97	$39.14	$32.99	$30.43	$31.86	$39.81	$229.20	$1,135.76
29				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
30		Typical Usage: therms		43	95	131	141	117	82	609	39	23	17	15	16	23	134	743
31	**Winter 2012 - 2013**																	
32	Customer Charge	units @	$ 13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38								
33	First	50 units @	$0.4410	$18.74	$22.05	$22.05	$22.05	$22.05	$22.05	$128.99								
34	Over	50 units @	$0.3829	$0.00	$17.05	$31.06	$35.00	$25.58	$12.34	$121.03								
35		COG 1	$0.8159	$34.68						$34.68								
36		COG 2	$0.8159		$77.13					$77.13								
37		COG 3	$0.8935			$117.16				$117.16								
38		COG 4	$0.7600				$107.47			$107.47								
39		COG 5	$0.5700					$66.58		$66.58								
40		COG 6	$0.5700						$46.87	$46.87								
41	Winter Period 12-13 Weighted Avg. COG		$0.7392															
42		LDAC	$ 0.0720	$3.06	$6.81	$9.44	$10.18	$8.41	$5.92	$43.82								
43	**Summer 2012**																	
44	Customer Charge	units @	$ 13.73								$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38	
45	First	50 units @	$0.4410								$17.30	$10.36	$7.56				$35.21	
46	Over	50 units @	$0.4410								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
47		COG 1	$0.4264								$16.72						$16.72	
48		COG 2	$0.4006									$9.41					$9.41	
49		COG 3	$0.4006										$6.87				$6.87	
50		COG 4	$0.4297											$6.38			$6.38	
51		COG 5	$0.4297												$6.93		$6.93	
52		COG 6	$0.4014													$9.31	$9.31	
53	Summer Period 2012 Wighted Avg. COG		$0.4150															
54		LDAC	$ 0.0642								$2.52	$1.51	$1.10	$0.95	$1.04	$1.49	$8.61	
55			**TOTAL**	$70.21	$136.77	$193.44	$188.43	$136.35	$100.91	**$826.11**	$50.27	$35.01	$29.25	$21.07	$21.70	$24.53	$181.82	$1,007.94
56			**Change**	$2.36	$5.25	($2.90)	$15.75	$35.21	$24.78	**$80.45**	$4.70	$4.14	$3.74	$9.36	$10.16	$15.28	**$47.38**	$127.83
57			**% Chg**	3.36%	3.84%	-1.50%	8.36%	25.82%	24.56%	**9.74%**	9.35%	11.82%	12.78%	44.43%	46.84%	62.27%	**26.06%**	12.68%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 1,920 therms/year

Comparison of Winter 2013-2014 vs. Winter 2012-2013

1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		100	254	369	369	332	219	1,642	90	50	32	28	31	48	278	1,920
3	**Winter 2013 - 2014**																	
4	Customer Charge	units @	$ 31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
5	First	75 units @	$0.3122	$23.42	$23.42	$23.42	$23.42	$23.42	$23.42	$140.49								
6	Over	75 units @	$0.2647	$6.53	$47.33	$77.86	$77.86	$68.05	$37.99	$315.61								
7		COG 1	$0.8706	$86.78						$86.78								
8		COG 2	$0.8706		$220.97					$220.97								
9		COG 3	$0.8706			$321.36				$321.36								
10		COG 4	$0.8706				$321.36			$321.36								
11		COG 5	$0.8706					$289.12		$289.12								
12		COG 6	$0.8706						$190.24	$190.24								
13		LDAC	$0.0238	$2.37	$6.04	$8.79	$8.79	$7.90	$5.20	$39.09								
14	**Summer 2013**																	
15	Customer Charge	units @	$ 31.40								$ 31.40	$31.40	$31.40	$31.40	$ 31.40	$31.40	$188.40	
16	First	75 units @	$0.2701								$20.26	$13.43					$33.69	
		75 units @ Temp	$0.3122										$10.01	$8.71	$9.59	$14.86	$43.17	
17	Over	75 units @	$0.2226								$3.37	$0.00					$3.37	
		75 unitis @ Temp	$0.2647										$0.00	$0.00	$0.00	$0.00	$0.00	
18		COG 1	$0.5780								$52.09						$52.09	
19		COG 2	$0.6085									$30.26					$30.26	
20		COG 3	$0.6085										$19.51				$19.51	
21		COG 4	$0.6085											$16.98			$16.98	
22		COG 5	$0.6085												$18.69		$18.69	
23		COG 6	$0.6085													$28.95	$28.95	
24	Summer Period 2013 Weighted Avg. COG		$0.5986															
25		LDAC	$ 0.0551								$4.97	$2.74	$1.77	$1.54	$1.69	$2.62	$15.32	
26		**TOTAL**		$150.50	$329.16	$462.82	$462.82	$419.89	$288.24	**$2,113.42**	$112.08	$77.83	$62.69	$58.63	$61.38	$77.83	$450.44	$2,563.86
27				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
28		Typical Usage: therms		100	254	369	369	332	219	1,642	90	50	32	28	31	48	278	1,920
29	**Winter 2012 - 2013**																	
30	Customer Charge	units @	$ 31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
31	First	75 units @	$0.2701	$20.26	$20.26	$20.26	$20.26	$20.26	$20.26	$121.55								
32	Over	75 units @	$0.2226	$5.49	$39.80	$65.47	$65.47	$57.23	$31.95	$265.42								
33		COG 1	$0.8279	$82.52						$82.52								
34		COG 2	$0.8279		$210.13					$210.13								
35		COG 3	$0.8279			$305.60				$305.60								
36		COG 4	$0.9055				$334.24			$334.24								
37		COG 5	$0.7720					$256.38		$256.38								
38		COG 6	$0.5820						$127.17	$127.17								
39	Winter Period 12-13 Weighted Avg. COG		$0.8013															
40		LDAC	$ 0.0720	$7.18	$18.27	$26.58	$26.58	$23.91	$15.73	$118.25								
41	**Summer 2012**																	
42	Customer Charge	units @	$ 31.40								$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40	
43	First	75 units @	$0.2701								$20.26	$13.43	$8.66				$42.35	
44	Over	75 units @	$0.2226								$3.37	$0.00	$0.00				$3.37	
45		COG 1	$0.4597								$41.43						$41.43	
46		COG 2	$0.4339									$21.58					$21.58	
47		COG 3	$0.4339										$13.91				$13.91	
48		COG 4	$0.4630											$12.92			$12.92	
49		COG 5	$0.4347												$13.35		$13.35	
50		COG 6	$0.4347													$20.68	$20.68	
51	Summer Period 2012 Wighted Avg. COG		$0.4454															
52		LDAC	$ 0.0435								$3.92	$2.16	$1.39	$1.21	$1.34	$2.07	$12.10	
53		**TOTAL**		$146.85	$319.87	$449.31	$477.95	$389.17	$226.51	**$2,009.66**	$100.37	$68.57	$55.37	$45.54	$46.09	$54.15	$370.09	$2,379.75
54		**Change**		$3.65	$9.29	$13.51	($15.13)	$30.72	$61.73	**$103.76**	$11.71	$9.26	$7.32	$13.10	$15.29	$23.68	**$80.35**	$184.11
55		**% Chg**		2.48%	2.90%	3.01%	-3.17%	7.89%	27.25%	**5.16%**	11.66%	13.50%	13.22%	28.76%	33.17%	43.72%	**21.71%**	7.74%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 20,565 therms/year

Comparison of Winter 2013-2014 vs. Winter 2012-2013

1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		1,305	2,653	3,566	3,920	3,254	2,169	16,868	1,048	667	442	393	481	667	3,698	20,565
3	**Winter 2013 - 2014**																	
4	Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
5	All	units @	$0.2437	$318.03	$646.65	$868.98	$955.21	$793.09	$528.70	$4,110.66								
6		COG 1	$0.8706	$1,136.15						$1,136.15								
7		COG 2	$0.8706		$2,310.09					$2,310.09								
8		COG 3	$0.8706			$3,104.37				$3,104.37								
9		COG 4	$0.8706				$3,412.42			$3,412.42								
10		COG 5	$0.8706					$2,833.27		$2,833.27								
11		COG 6	$0.8706						$1,888.73	$1,888.73								
12		LDAC	$0.0238	$31.06	$63.15	$84.87	$93.29	$77.45	$51.63	$401.45								
13	**Summer 2013**																	
14	Customer Charge	units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
15	All	units @	$0.1557								$163.16	$103.78					$266.94	
	All	units @ Temp	$0.1978										$87.49	$77.82	$95.10	$131.86	$392.27	
16		COG 1	$0.5780								$605.71						$605.71	
17		COG 2	$0.6085									$405.59					$405.59	
18		COG 3	$0.6085										$269.15				$269.15	
19		COG 4	$0.6085											$239.39			$239.39	
20		COG 5	$0.6085												$292.55		$292.55	
21		COG 6	$0.6085													$405.65	$405.65	
22	Summer Period 2013 Weighted Avg. COG		$0.5999															
23		LDAC	$ 0.0266								$27.88	$17.73	$11.77	$10.46	$12.79	$17.73	$98.36	
24			**TOTAL**	$1,579.45	$3,114.10	$4,152.43	$4,555.12	$3,798.03	$2,563.27	**$19,762.40**	$890.96	$621.31	$462.62	$421.88	$494.65	$649.45	$3,540.87	$23,303.26
25				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
26		Typical Usage: therms		1,305	2,653	3,566	3,920	3,254	2,169	16,868	1,048	667	442	393	481	667	3,698	20,565
27	**Winter 2012 - 2013**																	
28	Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
29	All	units @	$0.2016	$263.09	$534.94	$718.86	$790.19	$656.08	$437.36	$3,400.53								
30		COG 1	$0.8279	$1,080.42						$1,080.42								
31		COG 2	$0.8279		$2,196.79					$2,196.79								
32		COG 3	$0.8279			$2,952.11				$2,952.11								
33		COG 4	$0.8935				$3,502.18			$3,502.18								
34		COG 5	$0.7720					$2,512.39		$2,512.39								
35		COG 6	$0.5820						$1,262.62	$1,262.62								
36	Winter Period 12-13 Weighted Avg. COG		$0.8007															
37		LDAC	$ 0.0435	$56.77	$115.42	$155.11	$170.50	$141.57	$94.37	$733.75								
38	**Summer 2012**																	
39	Customer Charge	units @	$ 94.21								$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26	
40	All	units @	$0.1557								$163.16	$103.78	$68.87				$335.81	
41		COG 1	$0.4597								$481.74						$481.74	
42		COG 2	$0.4339									$289.21					$289.21	
43		COG 3	$0.4339										$191.92				$191.92	
44		COG 4	$0.4630											$182.15			$182.15	
45		COG 5	$0.4347												$208.99		$208.99	
46		COG 6	$0.4347													$289.79	$289.79	
47	Summer Period 2012 Wighted Avg. COG		$0.4446															
48		LDAC	$ 0.0435								$45.59	$28.99	$19.24	$17.11	$20.91	$29.00	$160.85	
49			**TOTAL**	$1,494.49	$2,941.36	$3,920.30	$4,557.08	$3,404.25	$1,888.57	**$18,206.05**	$784.70	$516.20	$374.24	$293.47	$324.12	$412.99	$2,705.72	$20,911.77
50			**Change**	$84.96	$172.74	$232.13	($1.96)	$393.78	$674.70	**$1,556.35**	$106.26	$105.11	$88.37	$128.41	$170.53	$236.46	**$835.15**	$2,391.50
51			**% Chg**	5.68%	5.87%	5.92%	-0.04%	11.57%	35.73%	**8.55%**	13.54%	20.36%	23.61%	43.76%	52.61%	57.25%	**30.87%**	11.44%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 17,447 therms/year

Comparison of Winter 2013-2014 vs. Winter 2012-2013

1					**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
2			Typical Usage: therms		1,337	1,708	1,948	2,022	1,856	1,607	10,479	1,277	1,170	1,066	1,188	1,078	1,188	6,968	17,447
3	**Winter 2013 - 2014**																		
4	Customer Charge		units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
5	First	1,300	units @	$0.2270	$295.10	$295.10	$295.10	$295.10	$295.10	$295.10	$1,770.60								
6	Over	1,300	units @	$0.1903	$7.05	$77.73	$123.31	$137.43	$105.85	$58.44	$509.81								
7			COG 1	$0.7764	$1,038.07						$1,038.07								
8			COG 2	$0.7764		$1,326.44					$1,326.44								
9			COG 3	$0.7764			$1,512.39				$1,512.39								
10			COG 4	$0.7764				$1,570.03			$1,570.03								
11			COG 5	$0.7764					$1,441.19		$1,441.19								
12			COG 6	$0.7764						$1,247.74	$1,247.74								
13			LDAC	$0.0238	$31.82	$40.66	$46.36	$48.13	$44.18	$38.25	$249.40								
14	**Summer 2013**																		
15	Customer Charge		units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
16	First	1,000	units @	$0.1325								$132.50	$132.50					$265.00	
17	First	1,000	units @ Temp	$0.1746										$174.60	$174.60	$174.60	$174.60	$698.40	
18	Over	1,000	units @	$0.1011								$28.01	$17.23					$45.25	
19	Over	1,000	units @ Temp	$0.1432										$9.48	$26.94	$11.23	$26.90	$74.56	
20			COG 1	$0.5180								$661.54						$661.54	
21			COG 2	$0.5485									$642.00					$642.00	
22			COG 3	$0.5485										$584.83				$584.83	
23			COG 4	$0.5485											$651.69			$651.69	
24			COG 5	$0.5485												$591.53		$591.53	
25			COG 6	$0.5485													$651.53	$651.53	
26	Summer Period 2013 Weighted Avg. COG			$0.5429															
27			LDAC	$ 0.0266								$33.97	$31.13	$28.36	$31.60	$28.69	$31.60	$185.35	
28				**TOTAL**	$1,466.24	$1,834.14	$2,071.37	$2,144.91	$1,980.53	$1,733.74	**$11,230.93**	$950.23	$917.07	$891.49	$979.04	$900.26	$978.83	$5,616.92	$16,847.85
28					**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
29			Typical Usage: therms		1,337	1,708	1,948	2,022	1,856	1,607	10,479	1,277	1,170	1,066	1,188	1,078	1,188	6,968	17,447
30	**Winter 2012 - 2013**																		
31	Customer Charge		units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
32	First	1,300	units @	$0.1849	$240.37	$240.37	$240.37	$240.37	$240.37	$240.37	$1,442.22								
33	Over	1,300	units @	$0.1482	$5.49	$60.53	$96.03	$107.03	$82.44	$45.51	$397.02								
34			COG 1	$0.7507	$1,003.71						$1,003.71								
35			COG 2	$0.7507		$1,282.53					$1,282.53								
36			COG 3	$0.7507			$1,462.33				$1,462.33								
37			COG 4	$0.8283				$1,674.99			$1,674.99								
38			COG 5	$0.6948					$1,289.72		$1,289.72								
39			COG 6	$0.5820						$935.32	$935.32								
40	Winter Period 12-13 Weighted Avg. COG			$0.7299															
41			LDAC	$ 0.0435	$58.16	$74.32	$84.74	$87.97	$80.75	$69.91	$455.83								
42	**Summer 2012**																		
43	Customer Charge		units @	$ 94.21								$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26	
44	First	1,000	units @	$0.1325								$132.50	$132.50	$132.50				$397.50	
45	Over	1,000	units @	$0.1011								$28.01	$17.23	$6.70				$51.94	
46			COG 1	$0.3835								$489.77						$489.77	
47			COG 2	$0.3577									$418.67					$418.67	
48			COG 3	$0.3577										$381.39				$381.39	
49			COG 4	$0.3868											$459.57			$459.57	
50			COG 5	$0.3585												$386.62		$386.62	
51			COG 6	$0.3585													$425.84	$425.84	
52	Summer Period 2012 Wighted Avg. COG			$0.3677															
53			LDAC	$ 0.0435								$55.55	$50.91	$46.38	$51.68	$46.91	$51.67	$303.12	
54				**TOTAL**	$1,401.93	$1,751.96	$1,977.67	$2,204.56	$1,787.48	$1,385.32	**$10,508.94**	$800.04	$713.53	$661.18	$605.46	$527.75	$571.72	$3,879.68	$14,388.62
55				**Change**	$64.31	$82.18	$93.70	($59.65)	$193.05	$348.42	**$722.00**	$150.19	$203.54	$230.31	$373.58	$372.51	$407.11	**$1,737.24**	$2,459.24
56				**% Chg**	4.59%	4.69%	4.74%	-2.71%	10.80%	25.15%	**6.87%**	18.77%	28.53%	34.83%	61.70%	70.59%	71.21%	**44.78%**	17.09%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Winter 2013-2014 vs. Actual Winter 2012-2013

Residential Heating	**Winter 2012-2013**	**Winter 2013- 2014**
Customer Charge	$13.73	$13.73
First 50 Therms	$0.4410	$0.4831
Over 50 therms	$0.3829	$0.4250
LDAC	$0.0720	$0.0446
CGA	$0.7392	$0.8567

	Usage (Therms)	**Winter 2012-2013 Bill Amount**	**Winter 2013-2014 Bill Amount**	**Total Bill**		**Base Rate**		**CGA**		**LDAC**	
	5	$19.99	$20.65	$0.66	3.3%	$0.21	1.1%	$0.59	3.0%	($0.14)	-0.7%
	10	$26.25	$27.57	$1.32	5.0%	$0.42	1.6%	$1.17	4.5%	($0.27)	-1.0%
	20	$38.77	$41.42	$2.64	6.8%	$0.84	2.2%	$2.35	6.1%	($0.55)	-1.4%
	25	$45.04	$48.34	$3.30	7.3%	$1.05	2.3%	$2.94	6.5%	($0.69)	-1.5%
	30	$51.30	$55.26	$3.97	7.7%	$1.26	2.5%	$3.52	6.9%	($0.82)	-1.6%
	45	$70.08	$76.03	$5.95	8.5%	$1.89	2.7%	$5.29	7.5%	($1.23)	-1.8%
Average Monthly	50	$76.34	$82.95	$6.61	8.7%	$2.11	2.8%	$5.87	7.7%	($1.37)	-1.8%
	75	$106.19	$116.11	$9.91	9.3%	$3.16	3.0%	$8.81	8.3%	($2.06)	-1.9%
	125	$165.90	$182.42	$16.52	10.0%	$5.27	3.2%	$14.69	8.9%	($3.43)	-2.1%
	150	$195.75	$215.58	$19.83	10.1%	$6.32	3.2%	$17.62	9.0%	($4.11)	-2.1%
	200	$255.46	$281.90	$26.44	10.3%	$8.43	3.3%	$23.50	9.2%	($5.48)	-2.1%

Schedule 9

Northern Utilities New Hampshire Division
Period Covered: November 1, 2013 - April 30, 2014
Variance Analysis

		2012-2013 Winter (6 months actual)			Forecast Winter 2013-2014 (6 months proposed)			Variance		
1	Therm Sales	26,962,970			27,891,158			928,188		
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		$ 14,871,693	$ 0.5516		$ 14,271,040	$ 0.5117		$ (600,653)	$ (0.0399)
7										
8	Purchased Gas		11,013,561	0.4085		11,116,950	0.3986		$ 103,389	$ (0.0099)
9										
10	Storage & Peaking Gas		2,774,896	0.1029		4,717,787	0.1691		$ 1,942,891	$ 0.0662
11										
12	Hedging (Gain)/Loss		587,661	0.0218		144,792	0.0052		(442,869)	(0.0166)
13										
14										
15	Total Volumes and Cost		$ 29,247,811	$ 1.0847	$ -	$ 30,250,569	$ 1.0846	$ -	$ 1,002,758	$ (0.0001)
16										
17	Prior Period Balance		($3,105,739)	$ (0.1152)		$ (2,128,249)	$ (0.0763)		$ 977,490	$ 0.0389
18						$ -	$ -		$ -	$ -
19	Interest		$ (26,148)	$ (0.0010)		23,596	$ 0.0008		49,744	$ 0.0018
20	Refunds from Suppliers		-	$ -		(449,048)	$ (0.0161)		(449,048)	$ (0.0161)
21	Off-system Sales		(4,237,089)	$ (0.1571)						
22	Prior Period Adjustment									
23	Interruptible Sales Margin		-	$ -		-	$ -		-	$ -
24	Capacity Release & Asset Management		(2,947,252)	$ (0.1057)		$ (4,660,791)	$ (0.1671)		(1,713,539)	$ (0.0614)
25	Working Capital Allowance		(1,852)	$ (0.0001)		19,229	$ 0.0007		21,081	$ 0.0008
26	Bad Debt Allowance		(71,949)	$ (0.0027)		$ 191,220	$ 0.0069		263,169	$ 0.0095
27	Fuel Inventory Financing		3,824	$ 0.0001		5,527	$ 0.0002		1,703	$ 0.0001
28	Local Production and Storage		307,762	$ 0.0114		307,762	$ 0.0110		-	$ -
29	Misc Overhead		321,752	$ 0.0119		333,160	$ 0.0119		11,408	$ 0.0000
30										
31	Total Anticipated Indirect Cost of Gas		($9,756,691)	$ (0.3619)		(6,357,594)	$ (0.2279)		3,399,097	$ 0.1339
32	Total Adjusted Cost		19,491,120	$ 0.7229		23,892,976	$ 0.8567		4,401,856	$ 0.1338

Schedules 10A, 10B & Attachments, & 10C

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

Base Capacity Costs

1	**BASE SENDOUT BY CLASS**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**	
2	**Total Therms**									
3	Res Heat	381,486	394,202	394,202	356,054	394,202	381,486	4,632,800	2,301,632	Schedule 10B, LN 52
4	Res General	14,268	14,744	14,744	13,317	14,744	14,268	173,272	86,084	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	77,431	80,012	80,012	72,269	80,012	69,607	932,501	459,341	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	122,409	126,489	126,489	114,248	126,489	122,409	1,486,542	738,532	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	93,669	96,792	96,792	87,425	96,792	93,669	1,137,528	565,138	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	105,311	108,821	108,821	98,290	108,821	105,311	1,278,904	635,375	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	7,933	8,198	8,198	7,405	8,198	7,933	96,344	47,865	Schedule 10B, LN 58
10	G42 High Annual-High Winter	18,008	18,608	18,608	16,807	18,608	18,008	218,686	108,646	Schedule 10B, LN 59
11	Total Firm Sales	820,515	847,865	847,865	765,814	847,865	812,691	9,956,578	4,942,614	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	46.49%	46.49%	46.49%	46.49%	46.49%	46.94%			LN 3 / LN 11
15	Res General	1.74%	1.74%	1.74%	1.74%	1.74%	1.76%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	9.44%	9.44%	9.44%	9.44%	9.44%	8.57%			LN 5 / LN 11
17	G40 Low Annual-High Winter	14.92%	14.92%	14.92%	14.92%	14.92%	15.06%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	11.42%	11.42%	11.42%	11.42%	11.42%	11.53%			LN 7 / LN 11
19	G41 Med Annual-High Winter	12.83%	12.83%	12.83%	12.83%	12.83%	12.96%			LN 8 / LN 11
20	G52 High Annual-Low Winter	0.97%	0.97%	0.97%	0.97%	0.97%	0.98%			LN 9 / LN 11
21	G42 High Annual-High Winter	2.19%	2.19%	2.19%	2.19%	2.19%	2.22%			LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			LN 11 / LN 11
23										

24	**PIPELINE BASE DEMAND COSTS**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 77,704	$ 932,444	$ 466,222	Schedule 1A, LN 69
26	Res Heat	$ 36,127	$ 36,127	$ 36,127	$ 36,127	$ 36,127	$ 36,475	$ 433,874	$ 217,111	LN 25 * LN 14
27	Res General	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,351	$ 1,364	$ 16,227	$ 8,120	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 7,333	$ 7,333	$ 7,333	$ 7,333	$ 7,333	$ 6,655	$ 87,316	$ 43,319	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 11,592	$ 11,592	$ 11,592	$ 11,592	$ 11,592	$ 11,704	$ 139,218	$ 69,665	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 8,871	$ 8,871	$ 8,871	$ 8,871	$ 8,871	$ 8,956	$ 106,532	$ 53,309	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 9,973	$ 9,973	$ 9,973	$ 9,973	$ 9,973	$ 10,069	$ 119,773	$ 59,934	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 751	$ 751	$ 751	$ 751	$ 751	$ 759	$ 9,023	$ 4,515	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,705	$ 1,705	$ 1,705	$ 1,705	$ 1,705	$ 1,722	$ 20,481	$ 10,248	LN 25 * LN 21
34										
35	Residential	$ 37,478	$ 37,478	$ 37,478	$ 37,478	$ 37,478	$ 37,839	$ 450,101	$ 225,231	LN 26 + LN 27
36	SALES HLF CLASSES	$ 16,955	$ 16,955	$ 16,955	$ 16,955	$ 16,955	$ 16,370	$ 202,871	$ 101,143	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 23,271	$ 23,271	$ 23,271	$ 23,271	$ 23,271	$ 23,495	$ 279,472	$ 139,848	LN 29 + LN 31 + LN 33
38										

Remaining Capacity Costs

		Column A	Column B	Column C	Column D	
39		Design Day Demand (MMBtu)	Avg Daily Base Use Load (MMBtu)	Remaining Design Day Demand (MMBtu)	% of Total Remaining Design Day Demand	
40	Res Heat	21,721	1,536	20,185	50.13%	Company Analysis
41	Res General	368	56	312	0.77%	Company Analysis
42	G50 Low Annual-Low Winter	936	324	612	1.52%	Company Analysis
43	G40 Low Annual-High Winter	9,106	512	8,594	21.34%	Company Analysis
44	G51 Med Annual-Low Winter	1,531	384	1,147	2.85%	Company Analysis
45	G41 Med Annual-High Winter	7,907	631	7,276	18.07%	Company Analysis
46	G52 High Annual-Low Winter	151	19	132	0.33%	Company Analysis
47	G42 High Annual-High Winter	2,061	54	2,007	4.99%	Company Analysis
48	TOTAL	43,781	3,517	40,264	100.00%	Sum LN 40 : LN 47

49

50 **REMAINING PIPELINE DEMAND**

51		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 175,218	$ 363,548	$ 815,785	$ 434,110	$ 239,772	$ 96,392	$ 2,196,509	$ 2,124,826	Schedule 1A, LN 70
53										
54	Res Heat	$ 87,839	$ 182,252	$ 408,965	$ 217,626	$ 120,201	$ 48,323	$ 1,101,141	$ 1,065,205	LN 40 Col D * LN 52
55	Res General	$ 1,356	$ 2,813	$ 6,312	$ 3,359	$ 1,855	$ 746	$ 16,996	$ 16,441	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 2,663	$ 5,525	$ 12,399	$ 6,598	$ 3,644	$ 1,465	$ 33,384	$ 32,295	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 37,399	$ 77,597	$ 174,124	$ 92,658	$ 51,178	$ 20,574	$ 468,831	$ 453,531	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 4,990	$ 10,354	$ 23,234	$ 12,364	$ 6,829	$ 2,745	$ 62,558	$ 60,516	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 31,662	$ 65,693	$ 147,411	$ 78,443	$ 43,327	$ 17,418	$ 396,907	$ 383,954	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 574	$ 1,191	$ 2,672	$ 1,422	$ 785	$ 316	$ 7,194	$ 6,959	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 8,735	$ 18,123	$ 40,668	$ 21,641	$ 11,953	$ 4,805	$ 109,498	$ 105,924	LN 47 Col D * LN 52
62	TOTAL	$ 175,218	$ 363,548	$ 815,785	$ 434,110	$ 239,772	$ 96,392	$ 2,196,509	$ 2,124,826	Sum LN 54 : LN 61
63										
64	Residential	$ 89,195	$ 185,065	$ 415,277	$ 220,985	$ 122,057	$ 49,069	$ 1,118,138	$ 1,081,647	LN 54 + LN 55
65	SALES HLF CLASSES	$ 8,227	$ 17,070	$ 38,305	$ 20,383	$ 11,258	$ 4,526	$ 103,136	$ 99,770	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 77,796	$ 161,413	$ 362,203	$ 192,742	$ 106,457	$ 42,798	$ 975,236	$ 943,409	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

69		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 963,159	$ 1,998,394	$ 4,484,303	$ 2,386,268	$ 1,318,008	$ 529,861	$ 12,074,031	$ 11,679,992	Schedule 1A, LN 73
71										
72	Res Heat	$ 482,845	$ 1,001,823	$ 2,248,045	$ 1,196,270	$ 660,736	$ 265,627	$ 6,052,884	$ 5,855,347	LN 40 Col D * LN 70
73	Res General	$ 7,453	$ 15,463	$ 34,699	$ 18,464	$ 10,198	$ 4,100	$ 93,426	$ 90,377	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 14,639	$ 30,373	$ 68,156	$ 36,268	$ 20,032	$ 8,053	$ 183,510	$ 177,521	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 205,580	$ 426,545	$ 957,147	$ 509,334	$ 281,321	$ 113,095	$ 2,577,127	$ 2,493,022	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 27,431	$ 56,915	$ 127,715	$ 67,962	$ 37,538	$ 15,091	$ 343,874	$ 332,652	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 174,042	$ 361,107	$ 810,308	$ 431,196	$ 238,163	$ 95,745	$ 2,181,764	$ 2,110,561	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 3,154	$ 6,545	$ 14,687	$ 7,815	$ 4,317	$ 1,735	$ 39,544	$ 38,254	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 48,014	$ 99,622	$ 223,546	$ 118,958	$ 65,704	$ 26,414	$ 601,901	$ 582,258	LN 47 Col D * LN 70
80	TOTAL	$ 963,159	$ 1,998,394	$ 4,484,303	$ 2,386,268	$ 1,318,008	$ 529,861	$ 12,074,031	$ 11,679,992	Sum LN 72 : LN 79
81										
82	Residential	$ 490,298	$ 1,017,287	$ 2,282,744	$ 1,214,735	$ 670,935	$ 269,727	$ 6,146,311	$ 5,945,724	LN 72 + LN 73
83	SALES HLF CLASSES	$ 45,225	$ 93,833	$ 210,558	$ 112,046	$ 61,886	$ 24,879	$ 566,929	$ 548,427	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 427,636	$ 887,274	$ 1,991,002	$ 1,059,488	$ 585,187	$ 235,255	$ 5,360,792	$ 5,185,841	LN 75 + LN 77 + LN 79

85

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

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter	
87		**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ (397,147)	$ (796,767)	$ (1,756,372)	$ (946,493)	$ (534,126)	$ (229,887)	$ (4,660,791)	$ (4,660,791)	Schedule 1A, LN 76
89										
90	Res Heat	$ (199,096)	$ (399,430)	$ (880,494)	$ (474,490)	$ (267,765)	$ (115,245)	$ (2,336,521)	$ (2,336,521)	LN 40 Col D * LN 88
91	Res General	$ (3,073)	$ (6,165)	$ (13,590)	$ (7,324)	$ (4,133)	$ (1,779)	$ (36,064)	$ (36,064)	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ (6,036)	$ (12,110)	$ (26,695)	$ (14,386)	$ (8,118)	$ (3,494)	$ (70,838)	$ (70,838)	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ (84,769)	$ (170,065)	$ (374,887)	$ (202,023)	$ (114,006)	$ (49,068)	$ (994,817)	$ (994,817)	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ (11,311)	$ (22,692)	$ (50,022)	$ (26,957)	$ (15,212)	$ (6,547)	$ (132,742)	$ (132,742)	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ (71,764)	$ (143,975)	$ (317,374)	$ (171,030)	$ (96,516)	$ (41,540)	$ (842,200)	$ (842,200)	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ (1,301)	$ (2,610)	$ (5,752)	$ (3,100)	$ (1,749)	$ (753)	$ (15,265)	$ (15,265)	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ (19,798)	$ (39,720)	$ (87,557)	$ (47,184)	$ (26,627)	$ (11,460)	$ (232,345)	$ (232,345)	LN 47 Col D * LN 88
98	TOTAL	$ (397,147)	$ (796,767)	$ (1,756,372)	$ (946,493)	$ (534,126)	$ (229,887)	$ (4,660,791)	$ (4,660,791)	Sum LN 90 : LN 97
99										
100	Residential	$ (202,169)	$ (405,596)	$ (894,085)	$ (481,814)	$ (271,898)	$ (117,024)	$ (2,372,585)	$ (2,372,585)	LN 90 + LN 91
101	SALES HLF CLASSES	$ (18,648)	$ (37,412)	$ (82,469)	$ (44,442)	$ (25,080)	$ (10,794)	$ (218,845)	$ (218,845)	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ (176,331)	$ (353,759)	$ (779,818)	$ (420,237)	$ (237,148)	$ (102,068)	$ (2,069,361)	$ (2,069,361)	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter	
105		**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**	
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 77
107										
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117										
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115

121

122 **REMAINING RE-ENTRY FEE CREDIT**

123		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	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-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter	
142	Res Heat	$ 371,589	$ 784,645	$ 1,776,515	$ 939,405	$ 513,173	$ 198,704	$ 4,817,505	$ 4,584,031	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 5,735	$ 12,111	$ 27,421	$ 14,500	$ 7,921	$ 3,067	$ 74,358	$ 70,755	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 11,266	$ 23,789	$ 53,860	$ 28,481	$ 15,558	$ 6,024	$ 146,056	$ 138,978	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 158,211	$ 334,077	$ 756,384	$ 399,969	$ 218,493	$ 84,602	$ 2,051,142	$ 1,951,736	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 21,111	$ 44,577	$ 100,927	$ 53,369	$ 29,154	$ 11,289	$ 273,690	$ 260,426	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 133,939	$ 282,825	$ 640,345	$ 338,609	$ 184,973	$ 71,623	$ 1,736,471	$ 1,652,315	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 2,428	$ 5,126	$ 11,606	$ 6,137	$ 3,353	$ 1,298	$ 31,473	$ 29,948	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 36,951	$ 78,025	$ 176,657	$ 93,415	$ 51,030	$ 19,759	$ 479,054	$ 455,838	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 741,229	$ 1,565,175	$ 3,543,716	$ 1,873,885	$ 1,023,655	$ 396,366	$ 9,609,750	$ 9,144,027	Sum LN 142 : LN 149
151										
152	Residential	$ 377,324	$ 796,756	$ 1,803,936	$ 953,905	$ 521,094	$ 201,771	$ 4,891,863	$ 4,654,786	LN 142 + LN 143
153	SALES HLF CLASSES	$ 34,804	$ 73,492	$ 166,393	$ 87,987	$ 48,065	$ 18,611	$ 451,220	$ 429,352	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 329,101	$ 694,928	$ 1,573,387	$ 831,993	$ 454,496	$ 175,984	$ 4,266,667	$ 4,059,889	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

157		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter	
158	Res Heat	$ 407,716	$ 820,772	$ 1,812,643	$ 975,533	$ 549,300	$ 235,179	$ 5,251,378	$ 4,801,142	LN 142 + LN 26
159	Res General	$ 7,087	$ 13,462	$ 28,772	$ 15,851	$ 9,272	$ 4,431	$ 90,586	$ 78,875	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 18,599	$ 31,121	$ 61,193	$ 35,813	$ 22,891	$ 12,680	$ 233,372	$ 182,297	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 169,803	$ 345,669	$ 767,977	$ 411,561	$ 230,085	$ 96,306	$ 2,190,360	$ 2,021,401	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 29,981	$ 53,448	$ 109,797	$ 62,240	$ 38,025	$ 20,245	$ 380,223	$ 313,735	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 143,912	$ 292,798	$ 650,318	$ 348,582	$ 194,946	$ 81,692	$ 1,856,243	$ 1,712,250	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 3,179	$ 5,877	$ 12,358	$ 6,889	$ 4,104	$ 2,057	$ 40,496	$ 34,463	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 38,656	$ 79,731	$ 178,363	$ 95,120	$ 52,735	$ 21,481	$ 499,535	$ 466,086	LN 149 + LN 33
166	TOTAL	$ 818,933	$ 1,642,879	$ 3,621,420	$ 1,951,589	$ 1,101,359	$ 474,070	$ 10,542,193	$ 9,610,249	Sum LN 158 : LN 165
167										
168	Residential	$ 414,803	$ 834,234	$ 1,841,414	$ 991,383	$ 558,572	$ 239,610	$ 5,341,964	$ 4,880,017	LN 158 + LN 159
169	SALES HLF CLASSES	$ 51,759	$ 90,446	$ 183,348	$ 104,942	$ 65,020	$ 34,981	$ 654,091	$ 530,495	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 352,372	$ 718,198	$ 1,596,658	$ 855,264	$ 477,767	$ 199,479	$ 4,546,138	$ 4,199,737	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								11.21%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								88.79%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2013 - 2014 Period

Line No.	**Forecasted Normal Sales By Class- Therms** Calendar Month Firm Sales Volumes Normal Winter	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter
1	Res Heat	1,752,362	2,581,604	3,259,177	2,724,580	2,100,313	1,237,730	16,708,899	13,655,766
2	Res General	30,616	45,104	56,942	47,602	36,695	21,625	352,776	238,585
3	**Total Residential**	**1,782,979**	**2,626,708**	**3,316,119**	**2,772,182**	**2,137,008**	**1,259,354**	**17,061,674**	**13,894,351**
4	G50 Low Annual-Low Winter	97,931	144,273	182,139	152,263	117,376	69,170	1,382,849	763,151
5	G40 Low Annual-High Winter	860,134	1,267,161	1,599,742	1,337,340	1,030,923	607,530	7,682,498	6,702,829
6	G51 Med Annual-Low Winter	141,210	208,033	262,634	219,555	169,249	99,740	1,850,081	1,100,421
7	G41 Med Annual-High Winter	569,323	838,734	1,058,870	885,185	682,368	402,124	5,279,434	4,436,604
8	G52 High Annual-Low Winter	27,001	39,778	50,218	41,981	32,362	19,071	273,905	210,412
9	G42 High Annual-High Winter	100,528	148,099	186,969	156,301	120,489	71,005	927,510	783,390
10	**Total C&I**	**1,796,126**	**2,646,078**	**3,340,572**	**2,792,624**	**2,152,766**	**1,268,641**	**17,396,276**	**13,996,807**
11	**Total Sales**	**3,579,105**	**5,272,786**	**6,656,691**	**5,564,807**	**4,289,774**	**2,527,995**	**34,457,951**	**27,891,158**
12									
13	Residential Heat & Non Heat	1,782,979	2,626,708	3,316,119	2,772,182	2,137,008	1,259,354	17,061,674	13,894,351
14	SALES HLF CLASSES	266,142	392,084	494,991	413,799	318,987	187,982	3,506,835	2,073,984
15	SALES LLF CLASSES	1,529,984	2,253,994	2,845,581	2,378,826	1,833,779	1,080,659	13,889,441	11,922,823
16	**Total Firm Sales**	**3,579,105**	**5,272,786**	**6,656,691**	**5,564,807**	**4,289,774**	**2,527,995**	**34,457,951**	**27,891,158**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)								
20	Normal Winter	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**
21	Res Heat	1,763,318	2,597,631	3,279,358	2,741,483	2,113,422	1,245,546	16,813,682	13,740,758
22	Res General	30,808	45,384	57,295	47,898	36,924	21,761	355,001	240,070
23	G50 Low Annual-Low Winter	98,543	145,168	183,267	153,208	118,108	69,607	1,391,615	767,901
24	G40 Low Annual-High Winter	865,511	1,275,028	1,609,648	1,345,636	1,037,357	611,367	7,730,566	6,744,547
25	G51 Med Annual-Low Winter	142,093	209,325	264,260	220,917	170,306	100,370	1,861,789	1,107,270
26	G41 Med Annual-High Winter	572,882	843,941	1,065,426	890,677	686,627	404,664	5,312,510	4,464,217
27	G52 High Annual-Low Winter	27,170	40,025	50,529	42,242	32,564	19,192	275,627	211,722
28	G42 High Annual-High Winter	101,156	149,018	188,127	157,271	121,241	71,453	933,320	788,266
29	**Subtotal**								
30	Residential	1,794,125	2,643,015	3,336,653	2,789,381	2,150,347	1,267,307	17,168,683	13,980,828
31	SALES HLF CLASSES	267,806	394,518	498,056	416,366	320,978	189,169	3,529,031	2,086,893
32	SALES LLF CLASSES	1,539,549	2,267,987	2,863,201	2,393,584	1,845,225	1,087,484	13,976,396	11,997,029
33	**Total Firm Sales**	3,601,480	5,305,520	6,697,910	5,599,330	4,316,550	2,543,960	34,674,110	28,064,750

Northern Utilities - NEW HAMPSHIRE DIVISION
2013 - 2014 Period

Line No.	**Forecasted Normal Sales By Class- Therms** Calendar Month Firm Sales Volumes	
	Normal Winter	
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 & Unaccou	Unaccounted For)
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Company Use, LAUF, BTU) x 10
22	Res General	LN 2 x Adj factor (Company Use, LAUF, BTU) x 10
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Company Use, LAUF, BTU) x 10
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Company Use, LAUF, BTU) x 10
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Company Use, LAUF, BTU) x 10
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Company Use, LAUF, BTU) x 10
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Company Use, LAUF, BTU) x 10
28	G42 High Annual-High Winter	LN 9 x Adj factor (Company Use, LAUF, BTU) x 10
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

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

34		
35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	12,716
37	Res General	476
38	G50 Low Annual-Low Winter	2,581
39	G40 Low Annual-High Winter	4,080
40	G51 Med Annual-Low Winter	3,122
41	G41 Med Annual-High Winter	3,510
42	G52 High Annual-Low Winter	264
43	G42 High Annual-High Winter	600
44	**Subtotal**	
45	Residential	13,192
46	SALES HLF CLASSES	5,968
47	SALES LLF CLASSES	8,191
48	**Total Firm Sales**	**27,350**

49	**BASE SENDOUT BY CLASS - Therms**								
50	Days per Month	30	31	31	28	31	30		
51		**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**
52	Res Heat	381,486	394,202	394,202	356,054	394,202	381,486	4,632,800	2,301,632
53	Res General	14,268	14,744	14,744	13,317	14,744	14,268	173,272	86,084
54	G50 Low Annual-Low Winter	77,431	80,012	80,012	72,269	80,012	69,607	932,501	459,341
55	G40 Low Annual-High Winter	122,409	126,489	126,489	114,248	126,489	122,409	1,486,542	738,532
56	G51 Med Annual-Low Winter	93,669	96,792	96,792	87,425	96,792	93,669	1,137,528	565,138
57	G41 Med Annual-High Winter	105,311	108,821	108,821	98,290	108,821	105,311	1,278,904	635,375
58	G52 High Annual-Low Winter	7,933	8,198	8,198	7,405	8,198	7,933	96,344	47,865
59	G42 High Annual-High Winter	18,008	18,608	18,608	16,807	18,608	18,008	218,686	108,646
60	**Subtotal**								
61	Residential	395,754	408,946	408,946	369,370	408,946	395,754	4,806,072	2,387,716
62	SALES HLF CLASSES	179,033	185,001	185,001	167,098	185,001	171,210	2,166,373	1,072,344
63	SALES LLF CLASSES	245,727	253,918	253,918	229,345	253,918	245,727	2,984,133	1,482,554
64	**Total Firm Sales**	820,515	847,865	847,865	765,814	847,865	812,691	9,956,578	4,942,614
65									
66	**REMAINING SENDOUT BY CLASS - Therms**								
67		**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**
68	Res Heat	1,381,832	2,203,429	2,885,156	2,385,430	1,719,220	864,060	12,180,882	11,439,126
69	Res General	16,540	30,641	42,551	34,581	22,181	7,493	181,729	153,986
70	G50 Low Annual-Low Winter	21,112	65,157	103,255	80,939	38,097	-	459,114	308,560
71	G40 Low Annual-High Winter	743,102	1,148,539	1,483,159	1,231,388	910,868	488,958	6,244,024	6,006,014
72	G51 Med Annual-Low Winter	48,424	112,533	167,469	133,492	73,514	6,700	724,261	542,132
73	G41 Med Annual-High Winter	467,571	735,120	956,605	792,387	577,806	299,353	4,033,606	3,828,841
74	G52 High Annual-Low Winter	19,236	31,827	42,331	34,837	24,366	11,258	179,282	163,857
75	G42 High Annual-High Winter	83,149	130,410	169,519	140,463	102,633	53,446	714,633	679,620
76	**Subtotal**								
77	Residential	1,398,371	2,234,069	2,927,707	2,420,010	1,741,401	871,553	12,362,610	11,593,112
78	SALES HLF CLASSES	88,772	209,517	313,055	249,268	135,977	17,959	1,362,658	1,014,548
79	SALES LLF CLASSES	1,293,822	2,014,069	2,609,283	2,164,238	1,591,307	841,757	10,992,263	10,514,475
80	**Total Firm Sales**	2,780,965	4,457,655	5,850,045	4,833,516	3,468,685	1,731,269	24,717,532	23,122,136

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

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

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

	Total Division Metered Deliveries (Dth)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	540,836	512,746	28,090	5.5%	15,540	12,550	549,801	-8,965	-1.6%	29,689	-38,655
Dec	847,002	801,576	45,427	5.7%	24,618	20,809	791,110	55,892	7.1%	43,011	12,881
Jan	1,110,192	1,045,501	64,692	6.2%	39,822	24,870	1,015,931	94,261	9.3%	62,981	31,280
Feb	1,143,366	1,076,884	66,482	6.2%	42,198	24,284	1,004,485	138,881	13.8%	63,160	75,722
Mar	1,017,419	955,266	62,153	6.5%	38,420	23,733	905,458	111,961	12.4%	58,505	53,456
Apr	746,435	719,023	27,412	3.8%	32,249	-4,838	691,661	54,773	7.9%	43,150	11,623
May	465,075	450,466	14,609	3.2%	20,617	-6,008	429,260	35,815	8.3%	25,967	9,848
Jun	377,322	366,474	10,849	3.0%	17,160	-6,312	348,153	29,169	8.4%	21,383	7,787
Jul	327,299	318,458	8,842	2.8%	15,141	-6,299	300,179	27,121	9.0%	19,109	8,012
Aug	329,697	320,705	8,992	2.8%	15,602	-6,611	302,240	27,456	9.1%	20,993	6,463
Sep	328,757	318,843	9,914	3.1%	16,229	-6,315	303,338	25,419	8.4%	22,979	2,440
Oct	287,628	279,288	8,339	3.0%	14,603	-6,264	271,324	16,304	6.0%	22,281	-5,977
Peak	5,405,250	5,110,994	294,256	5.8%	192,848	101,408	4,958,446	446,804	9.0%	297,760	149,044
Off-Peak	2,115,778	2,054,233	61,545	3.0%	99,353	-37,809	1,954,494	161,284	8.3%	134,543	26,742
Annual	7,521,028	7,165,227	355,800	5.0%	292,201	63,599	6,912,939	608,088	8.8%	445,569	162,519

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

	Total Division Meter Counts						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	30,297	29,406	891	3.0%	28,745	1,552	5.4%
Dec	30,411	29,505	906	3.1%	28,843	1,568	5.4%
Jan	30,715	29,588	1,127	3.8%	28,922	1,793	6.2%
Feb	30,769	29,609	1,160	3.9%	28,949	1,820	6.3%
Mar	30,825	29,633	1,192	4.0%	28,954	1,871	6.5%
Apr	30,820	29,497	1,323	4.5%	29,010	1,810	6.2%
May	30,770	29,424	1,347	4.6%	29,015	1,755	6.0%
Jun	30,749	29,374	1,375	4.7%	28,970	1,779	6.1%
Jul	30,825	29,426	1,399	4.8%	28,980	1,845	6.4%
Aug	30,976	29,539	1,437	4.9%	28,964	2,012	6.9%
Sep	31,258	29,744	1,514	5.1%	29,057	2,201	7.6%
Oct	31,631	30,060	1,572	5.2%	29,231	2,400	8.2%
Peak	30,640	29,540	1,100	3.7%	28,904	1,736	6.0%
Off-Peak	31,035	29,594	1,441	4.9%	29,036	1,999	6.9%
Annual	30,837	29,567	1,270	4.3%	28,970	1,867	6.4%

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

	Total Division Use Per Meter						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	17.85	17.44	0.41	2.4%	19.13	-1.28	-6.7%
Dec	27.85	27.17	0.68	2.5%	27.43	0.42	1.5%
Jan	36.14	35.34	0.81	2.3%	35.13	1.02	2.9%
Feb	37.16	36.37	0.79	2.2%	34.70	2.46	7.1%
Mar	33.01	32.24	0.77	2.4%	31.27	1.73	5.5%
Apr	24.22	24.38	-0.16	-0.6%	23.84	0.38	1.6%
May	15.11	15.31	-0.20	-1.3%	14.79	0.32	2.2%
Jun	12.27	12.48	-0.21	-1.6%	12.02	0.25	2.1%
Jul	10.62	10.82	-0.20	-1.9%	10.36	0.26	2.5%
Aug	10.64	10.86	-0.21	-2.0%	10.44	0.21	2.0%
Sep	10.52	10.72	-0.20	-1.9%	10.44	0.08	0.7%
Oct	9.09	9.29	-0.20	-2.1%	9.28	-0.19	-2.0%
Peak	176.41	173.02	3.39	2.0%	171.55	4.74	2.8%
Off-Peak	68.17	69.41	-1.24	-1.8%	67.31	0.93	1.4%
Annual	243.89	242.34	1.56	0.6%	238.62	5.67	2.4%

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

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

	Residential Non-Heat Metered Deliveries (Dth)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	2,330	2,198	132	6.0%	132	0	2,928	-598	-20.4%	-84	-514
Dec	3,695	3,475	219	6.3%	219	0	3,908	-213	-5.5%	-73	-140
Jan	4,805	4,503	302	6.7%	302	0	5,307	-502	-9.5%	-88	-413
Feb	5,078	4,777	301	6.3%	301	0	5,294	-216	-4.1%	-81	-135
Mar	4,291	4,055	236	5.8%	236	0	4,802	-511	-10.6%	-76	-436
Apr	3,660	3,711	-51	-1.4%	-51	0	3,758	-98	-2.6%	-98	0
May	2,336	2,368	-32	-1.4%	-32	0	2,449	-113	-4.6%	-113	0
Jun	2,184	2,214	-30	-1.4%	-30	0	2,188	-4	-0.2%	-4	0
Jul	1,738	1,762	-24	-1.3%	-24	0	1,735	3	0.2%	3	0
Aug	1,633	1,655	-22	-1.3%	-22	0	1,627	5	0.3%	5	0
Sep	1,760	1,783	-24	-1.3%	-24	0	1,742	18	1.0%	18	0
Oct	1,769	1,792	-24	-1.3%	-24	0	1,699	69	4.1%	69	0
Peak	23,859	22,720	1,139	5.0%	1,139	0	25,997	-2,138	-8.2%	-526	-1,612
Off-Peak	11,419	11,575	-156	-1.3%	-156	0	11,440	-21	-0.2%	8	-29
Annual	35,278	34,294	983	2.9%	983	0	37,437	-2,159	-5.8%	-371	-1,788

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

	Total Division Meter Counts						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1,544	1,457	87	6.0%	1,590	-46	-2.9%
Dec	1,543	1,451	92	6.3%	1,572	-29	-1.9%
Jan	1,541	1,444	97	6.7%	1,567	-26	-1.7%
Feb	1,539	1,448	91	6.3%	1,563	-24	-1.5%
Mar	1,537	1,453	84	5.8%	1,562	-25	-1.6%
Apr	1,536	1,557	-21	-1.4%	1,577	-41	-2.6%
May	1,534	1,555	-21	-1.4%	1,608	-74	-4.6%
Jun	1,532	1,553	-21	-1.4%	1,535	-3	-0.2%
Jul	1,531	1,552	-21	-1.3%	1,528	3	0.2%
Aug	1,529	1,550	-21	-1.3%	1,524	5	0.3%
Sep	1,527	1,548	-21	-1.3%	1,512	15	1.0%
Oct	1,526	1,546	-20	-1.3%	1,466	60	4.1%
Peak	1,540	1,468	72	4.9%	1,572	-32	-2.0%
Off-Peak	1,530	1,551	-21	-1.3%	1,529	1	0.1%
Annual	1,535	1,510	25	1.7%	1,550	-15	-1.0%

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

	Total Division Use Per Meter						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1.51	1.51	0.00	0.0%	1.84	-0.33	-18.1%
Dec	2.39	2.39	0.00	0.0%	2.49	-0.09	-3.7%
Jan	3.12	3.12	0.00	0.0%	3.39	-0.27	-7.9%
Feb	3.30	3.30	0.00	0.0%	3.39	-0.09	-2.6%
Mar	2.79	2.79	0.00	0.0%	3.07	-0.28	-9.2%
Apr	2.38	2.38	0.00	0.0%	2.38	0.00	0.0%
May	1.52	1.52	0.00	0.0%	1.52	0.00	0.0%
Jun	1.43	1.43	0.00	0.0%	1.43	0.00	0.0%
Jul	1.14	1.14	0.00	0.0%	1.14	0.00	0.0%
Aug	1.07	1.07	0.00	0.0%	1.07	0.00	0.0%
Sep	1.15	1.15	0.00	0.0%	1.15	0.00	0.0%
Oct	1.16	1.16	0.00	0.0%	1.16	0.00	0.0%
Peak	15.49	15.47	0.02	0.1%	16.54	-1.06	-6.4%
Off-Peak	7.46	7.46	0.00	0.0%	7.48	0.00	0.0%
Annual	22.98	22.72	0.26	1.2%	24.15	-1.06	-4.4%

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

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

	Residential Heat Metered Deliveries (Dth)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	94,080	91,166	2,914	3.2%	2,914	0	114,973	-20,893	-18.2%	7,536	-28,429
Dec	209,952	203,634	6,318	3.1%	6,318	0	187,409	22,543	12.0%	12,132	10,411
Jan	294,389	283,279	11,109	3.9%	11,109	0	278,321	16,068	5.8%	20,343	-4,276
Feb	318,018	305,871	12,147	4.0%	12,147	0	282,495	35,523	12.6%	20,838	14,685
Mar	263,469	252,813	10,656	4.2%	10,656	0	246,873	16,596	6.7%	18,663	-2,066
Apr	185,668	176,417	9,251	5.2%	9,251	0	172,797	12,871	7.4%	12,871	0
May	88,466	83,996	4,471	5.3%	4,471	0	82,376	6,090	7.4%	6,090	0
Jun	52,994	50,256	2,738	5.4%	2,738	0	49,472	3,522	7.1%	3,522	0
Jul	38,835	36,800	2,034	5.5%	2,034	0	36,166	2,668	7.4%	2,668	0
Aug	33,872	32,059	1,813	5.7%	1,813	0	31,340	2,532	8.1%	2,532	0
Sep	37,138	35,074	2,064	5.9%	2,064	0	34,156	2,982	8.7%	2,982	0
Oct	54,009	50,936	3,073	6.0%	3,073	0	49,470	4,539	9.2%	4,539	0
Peak	1,365,577	1,313,181	52,395	4.0%	52,395	0	1,282,869	82,708	6.4%	91,363	-8,656
Off-Peak	305,313	289,120	16,193	5.6%	16,193	0	282,980	22,333	7.9%	22,588	-255
Annual	1,670,890	1,602,301	68,589	4.3%	68,589	0	1,565,849	105,041	6.7%	118,287	-13,246

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

	Total Division Meter Counts						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	22,135	21,449	686	3.2%	20,773	1,362	6.6%
Dec	22,209	21,541	668	3.1%	20,859	1,350	6.5%
Jan	22,451	21,604	847	3.9%	20,922	1,529	7.3%
Feb	22,490	21,631	859	4.0%	20,945	1,545	7.4%
Mar	22,555	21,643	912	4.2%	20,970	1,585	7.6%
Apr	22,580	21,455	1,125	5.2%	21,015	1,565	7.4%
May	22,557	21,417	1,140	5.3%	21,004	1,553	7.4%
Jun	22,561	21,395	1,166	5.4%	21,062	1,499	7.1%
Jul	22,660	21,473	1,187	5.5%	21,103	1,557	7.4%
Aug	22,799	21,579	1,220	5.7%	21,095	1,704	8.1%
Sep	23,025	21,745	1,280	5.9%	21,176	1,849	8.7%
Oct	23,275	21,951	1,324	6.0%	21,319	1,956	9.2%
Peak	22,403	21,554	850	3.9%	20,914	1,489	7.1%
Off-Peak	22,813	21,593	1,220	5.6%	21,127	1,686	8.0%
Annual	22,608	21,574	1,035	4.8%	21,020	1,588	7.6%

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

	Total Division Use Per Meter						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	4.25	4.25	0.00	0.0%	5.53	-1.28	-23.2%
Dec	9.45	9.45	0.00	0.0%	8.98	0.47	5.2%
Jan	13.11	13.11	0.00	0.0%	13.30	-0.19	-1.4%
Feb	14.14	14.14	0.00	0.0%	13.49	0.65	4.8%
Mar	11.68	11.68	0.00	0.0%	11.77	-0.09	-0.8%
Apr	8.22	8.22	0.00	0.0%	8.22	0.00	0.0%
May	3.92	3.92	0.00	0.0%	3.92	0.00	0.0%
Jun	2.35	2.35	0.00	0.0%	2.35	0.00	0.0%
Jul	1.71	1.71	0.00	0.0%	1.71	0.00	0.0%
Aug	1.49	1.49	0.00	0.0%	1.49	0.00	0.0%
Sep	1.61	1.61	0.00	0.0%	1.61	0.00	0.0%
Oct	2.32	2.32	0.00	0.0%	2.32	0.00	0.0%
Peak	60.95	60.93	0.03	0.0%	61.34	-0.44	-0.7%
Off-Peak	13.38	13.39	-0.01	0.0%	13.39	0.00	0.0%
Annual	73.91	74.27	-0.36	-0.5%	74.49	-0.44	-0.6%

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

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

	Total Division C&I Metered Deliveries (Dth)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	444,425	419,381	25,045	6.0%	7,630	17,415	431,899	12,526	2.9%	15,988	-3,462
Dec	633,356	594,467	38,889	6.5%	13,343	25,547	599,793	33,563	5.6%	23,122	10,440
Jan	810,999	757,719	53,280	7.0%	21,184	32,096	732,303	78,695	10.7%	32,994	45,701
Feb	820,270	766,235	54,035	7.1%	24,651	29,384	716,696	103,574	14.5%	33,279	70,295
Mar	749,658	698,397	51,261	7.3%	20,850	30,412	653,782	95,876	14.7%	31,575	64,301
Apr	557,106	538,895	18,211	3.4%	18,219	-8	515,105	42,001	8.2%	22,936	19,064
May	374,273	364,102	10,171	2.8%	12,865	-2,694	344,436	29,837	8.7%	14,861	14,976
Jun	322,144	314,004	8,140	2.6%	11,275	-3,135	296,492	25,652	8.7%	13,152	12,500
Jul	286,727	279,896	6,831	2.4%	10,182	-3,351	262,278	24,449	9.3%	11,778	12,671
Aug	294,192	286,991	7,201	2.5%	10,631	-3,430	269,273	24,919	9.3%	12,847	12,072
Sep	289,860	281,985	7,874	2.8%	11,149	-3,275	267,440	22,419	8.4%	14,148	8,272
Oct	231,850	226,560	5,290	2.3%	9,245	-3,955	220,154	11,696	5.3%	13,140	-1,444
Peak	4,015,815	3,775,093	240,721	6.4%	105,876	134,845	3,649,580	366,235	10.0%	158,111	208,123
Off-Peak	1,799,045	1,753,539	45,507	2.6%	65,346	-19,839	1,660,073	138,972	8.4%	81,016	57,956
Annual	5,814,860	5,528,632	286,228	5.2%	171,222	115,006	5,309,653	505,207	9.5%	244,537	260,670

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

	Total Division Meter Counts						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	6,618	6,500	118	1.8%	6,382	236	3.7%
Dec	6,659	6,513	146	2.2%	6,412	247	3.9%
Jan	6,723	6,540	183	2.8%	6,433	290	4.5%
Feb	6,740	6,530	210	3.2%	6,441	299	4.6%
Mar	6,732	6,537	195	3.0%	6,422	310	4.8%
Apr	6,704	6,485	219	3.4%	6,418	286	4.5%
May	6,679	6,451	228	3.5%	6,403	276	4.3%
Jun	6,656	6,425	231	3.6%	6,373	283	4.4%
Jul	6,634	6,401	233	3.6%	6,349	285	4.5%
Aug	6,648	6,410	237	3.7%	6,345	303	4.8%
Sep	6,706	6,451	255	4.0%	6,369	337	5.3%
Oct	6,831	6,563	268	4.1%	6,446	385	6.0%
Peak	6,696	6,517	179	2.7%	6,418	278	4.3%
Off-Peak	6,692	6,450	242	3.8%	6,381	311	4.9%
Annual	6,694	6,484	210	3.2%	6,399	295	4.6%

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

	Total Division Use Per Meter						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	67.15	64.52	2.63	4.1%	67.67	-0.52	-0.8%
Dec	95.11	91.27	3.84	4.2%	93.54	1.57	1.7%
Jan	120.63	115.86	4.77	4.1%	113.84	6.80	6.0%
Feb	121.70	117.34	4.36	3.7%	111.27	10.43	9.4%
Mar	111.35	106.84	4.52	4.2%	101.80	9.55	9.4%
Apr	83.10	83.10	0.00	0.0%	80.26	2.84	3.5%
May	56.04	56.44	-0.40	-0.7%	53.79	2.24	4.2%
Jun	48.40	48.87	-0.47	-1.0%	46.52	1.88	4.0%
Jul	43.22	43.73	-0.51	-1.2%	41.31	1.91	4.6%
Aug	44.25	44.77	-0.52	-1.2%	42.44	1.82	4.3%
Sep	43.22	43.71	-0.49	-1.1%	41.99	1.23	2.9%
Oct	33.94	34.52	-0.58	-1.7%	34.15	-0.21	-0.6%
Peak	599.73	579.23	20.50	3.5%	568.65	30.67	5.4%
Off-Peak	268.83	271.86	-3.03	-1.1%	260.17	8.87	3.4%
Annual	868.65	852.68	15.97	1.9%	829.71	39.54	4.8%

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

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

Forecast Calendar Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-13	3,062	175,236	86,013	9,793	56,932	14,121	10,053	2,700	0	357,910
Dec-13	4,510	258,160	126,716	14,427	83,873	20,803	14,810	3,978	0	527,279
Jan-14	5,694	325,918	159,974	18,214	105,887	26,263	18,697	5,022	0	665,669
Feb-14	4,760	272,458	133,734	15,226	88,519	21,955	15,630	4,198	0	556,481
Mar-14	3,670	210,031	103,092	11,738	68,237	16,925	12,049	3,236	0	428,977
Apr-14	2,162	123,773	60,753	6,917	40,212	9,974	7,100	1,907	0	252,800
May-14	2,309	61,725	19,806	12,528	17,039	15,156	2,914	1,284	0	132,761
Jun-14	1,642	43,890	14,083	8,908	12,116	10,777	2,072	913	0	94,401
Jul-14	1,433	38,307	12,292	7,775	10,575	9,406	1,808	797	0	82,392
Aug-14	1,497	40,019	12,841	8,123	11,047	9,826	1,889	832	0	86,073
Sep-14	1,651	44,142	14,164	8,960	12,186	10,839	2,084	918	0	94,942
Oct-14	2,889	77,231	24,781	15,676	21,320	18,963	3,646	1,606	0	166,111
Peak	23,859	1,365,577	670,283	76,315	443,660	110,042	78,339	21,041	0	2,789,116
Off-Peak	11,419	305,313	97,967	61,970	84,283	74,966	14,412	6,349	0	656,679
Total	35,278	1,670,890	768,250	138,285	527,943	185,008	92,751	27,391	0	3,445,795

Forecast Calendar Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-13	3,062	175,236	108,987	13,778	136,400	39,242	54,513	137,371	74,923	743,511
Dec-13	4,510	258,160	153,637	19,097	176,996	50,240	66,909	161,789	87,796	979,136
Jan-14	5,694	325,918	190,804	23,561	212,529	59,974	78,360	185,744	100,542	1,183,125
Feb-14	4,760	272,458	161,544	20,050	184,716	52,364	69,450	167,220	90,695	1,023,258
Mar-14	3,670	210,031	129,366	16,295	159,121	45,654	62,896	157,254	85,686	869,971
Apr-14	2,162	123,773	81,811	10,569	113,054	33,000	47,853	125,349	68,675	606,248
May-14	2,309	61,725	26,396	16,212	40,022	34,667	24,044	93,277	87,041	385,692
Jun-14	1,642	43,890	20,362	12,418	34,013	29,367	22,204	88,562	82,931	335,390
Jul-14	1,433	38,307	18,094	11,019	30,811	26,585	20,413	81,797	76,640	305,099
Aug-14	1,497	40,019	18,853	11,483	32,014	27,626	21,166	84,759	79,409	316,825
Sep-14	1,651	44,142	20,261	12,368	33,450	28,891	21,634	86,036	80,536	328,970
Oct-14	2,889	77,231	32,016	19,720	46,552	40,384	26,844	102,605	95,562	443,803
Peak	23,859	1,365,577	826,150	103,349	982,816	280,474	379,981	934,728	508,317	5,405,250
Off-Peak	11,419	305,313	135,982	83,221	216,862	187,521	136,305	537,036	502,120	2,115,778
Total	35,278	1,670,890	962,131	186,570	1,199,678	467,995	516,286	1,471,763	1,010,437	7,521,028

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-13	100%	100%	79%	71%	42%	36%	18%	2%	0%	48%
Dec-13	100%	100%	82%	76%	47%	41%	22%	2%	0%	54%
Jan-14	100%	100%	84%	77%	50%	44%	24%	3%	0%	56%
Feb-14	100%	100%	83%	76%	48%	42%	23%	3%	0%	54%
Mar-14	100%	100%	80%	72%	43%	37%	19%	2%	0%	49%
Apr-14	100%	100%	74%	65%	36%	30%	15%	2%	0%	42%
May-14	100%	100%	75%	77%	43%	44%	12%	1%	0%	34%
Jun-14	100%	100%	69%	72%	36%	37%	9%	1%	0%	28%
Jul-14	100%	100%	68%	71%	34%	35%	9%	1%	0%	27%
Aug-14	100%	100%	68%	71%	35%	36%	9%	1%	0%	27%
Sep-14	100%	100%	70%	72%	36%	38%	10%	1%	0%	29%
Oct-14	100%	100%	77%	79%	46%	47%	14%	2%	0%	37%
Peak	100%	100%	81%	74%	45%	39%	21%	2%	0%	52%
Off-Peak	100%	100%	72%	74%	39%	40%	11%	1%	0%	31%
Total	100%	100%	80%	74%	44%	40%	18%	2%	0%	46%

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

Forecast Bill Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-13	2,330	94,080	36,416	9,170	28,918	13,877	9,617	2,306		196,714
Dec-13	3,695	209,952	99,927	12,073	67,525	17,473	14,141	3,401		428,187
Jan-14	4,805	294,389	148,577	14,236	94,897	20,096	16,609	3,657		597,266
Feb-14	5,078	318,018	165,170	14,528	105,835	21,701	16,878	5,054		652,263
Mar-14	4,291	263,469	133,403	12,930	85,695	19,595	15,064	4,859		539,306
Apr-14	3,660	185,668	86,790	13,377	60,790	17,300	6,030	1,764		375,380
May-14	2,336	88,466	33,263	10,307	26,599	14,536	4,183	1,407		181,096
Jun-14	2,184	52,994	16,665	10,325	15,396	12,198	2,354	944		113,061
Jul-14	1,738	38,835	10,662	10,286	9,543	10,844	1,922	757		84,585
Aug-14	1,633	33,872	9,794	10,300	7,936	13,569	1,237	804		79,143
Sep-14	1,760	37,138	10,427	11,565	9,259	11,456	1,746	779		84,129
Oct-14	1,769	54,009	17,157	9,188	15,549	12,364	2,970	1,659		114,664
Peak	23,859	1,365,577	670,283	76,315	443,660	110,042	78,339	21,041	0	2,789,116
Off-Peak	11,419	305,313	97,967	61,970	84,283	74,966	14,412	6,349	0	656,679
Total	35,278	1,670,890	768,250	138,285	527,943	185,008	92,751	27,391	0	3,445,795

Forecast Bill Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-13	2,330	94,080	48,175	12,226	74,390	35,659	53,388	138,477	82,111	540,836
Dec-13	3,695	209,952	123,532	15,949	152,895	45,617	63,192	150,696	81,475	847,002
Jan-14	4,805	294,389	181,619	18,962	208,105	52,266	77,287	184,086	88,674	1,110,192
Feb-14	5,078	318,018	202,153	19,587	229,720	54,113	77,779	155,805	81,112	1,143,366
Mar-14	4,291	263,469	163,610	17,310	190,764	49,725	71,653	167,927	88,671	1,017,419
Apr-14	3,660	185,668	107,062	19,315	126,942	43,095	36,681	137,737	86,275	746,435
May-14	2,336	88,466	43,950	14,398	61,106	34,281	21,228	114,680	84,629	465,075
Jun-14	2,184	52,994	24,140	14,115	38,772	31,452	24,577	101,921	87,166	377,322
Jul-14	1,738	38,835	15,502	13,567	25,638	28,681	22,001	102,784	78,554	327,299
Aug-14	1,633	33,872	13,522	13,501	22,905	31,992	27,780	99,200	85,293	329,697
Sep-14	1,760	37,138	15,038	15,570	28,345	29,068	29,962	95,644	76,232	328,757
Oct-14	1,769	54,009	23,830	12,069	40,096	32,047	10,757	22,806	90,245	287,628
Peak	23,859	1,365,577	826,150	103,349	982,816	280,474	379,981	934,728	508,317	5,405,250
Off-Peak	11,419	305,313	135,982	83,221	216,862	187,521	136,305	537,036	502,120	2,115,778
Total	35,278	1,670,890	962,131	186,570	1,199,678	467,995	516,286	1,471,763	1,010,437	7,521,028

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-13	100%	100%	76%	75%	39%	39%	18%	2%	0%	36%
Dec-13	100%	100%	81%	76%	44%	38%	22%	2%	0%	51%
Jan-14	100%	100%	82%	75%	46%	38%	21%	2%	0%	54%
Feb-14	100%	100%	82%	74%	46%	40%	22%	3%	0%	57%
Mar-14	100%	100%	82%	75%	45%	39%	21%	3%	0%	53%
Apr-14	100%	100%	81%	69%	48%	40%	16%	1%	0%	50%
May-14	100%	100%	76%	72%	44%	42%	20%	1%	0%	39%
Jun-14	100%	100%	69%	73%	40%	39%	10%	1%	0%	30%
Jul-14	100%	100%	69%	76%	37%	38%	9%	1%	0%	26%
Aug-14	100%	100%	72%	76%	35%	42%	4%	1%	0%	24%
Sep-14	100%	100%	69%	74%	33%	39%	6%	1%	0%	26%
Oct-14	100%	100%	72%	76%	39%	39%	28%	7%	0%	40%
Peak	100%	100%	81%	74%	45%	39%	21%	2%	0%	52%
Off-Peak	100%	100%	72%	74%	39%	40%	11%	1%	0%	31%
Total	100%	100%	80%	74%	44%	40%	18%	2%	0%	46%

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

Month	Calendar Month Distribution Service Usage (Dth)	Estimated Company Use Factor	Estimated Company Use (Dth)	Billed Sales Service Deliveries (Dth)	Net Unbilled Sales Service Deliveries (Dth)	Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Lost and Unaccounted For (Percent)	Lost and Unaccounted For (Dth)	Estimated Division Sales Service Sendout (Dth)	Estimated Company-Managed Sales	Total Estimated City-Gate Sendout Requirement
Nov-13	743,511	0.02%	149	196,714	161,197	357,910	358,059	0.58%	2,089	360,148	49,745	409,893
Dec-13	979,136	0.02%	196	428,187	99,091	527,279	527,474	0.58%	3,078	530,552	218,878	749,430
Jan-14	1,183,125	0.02%	237	597,266	68,403	665,669	665,906	0.58%	3,885	669,791	298,470	968,261
Feb-14	1,023,258	0.02%	205	652,263	-95,782	556,481	556,685	0.58%	3,248	559,933	268,623	828,556
Mar-14	869,971	0.02%	174	539,306	-110,329	428,977	429,151	0.58%	2,504	431,655	159,184	590,839
Apr-14	606,248	0.02%	121	375,380	-122,580	252,800	252,921	0.58%	1,475	254,396	0	254,396
May-14	385,692	0.02%	77	181,096	-48,336	132,761	132,838	0.58%	775	133,613	0	133,613
Jun-14	335,390	0.02%	67	113,061	-18,660	94,401	94,468	0.58%	551	95,019	0	95,019
Jul-14	305,099	0.02%	61	84,585	-2,193	82,392	82,453	0.58%	481	82,934	0	82,934
Aug-14	316,825	0.02%	63	79,143	6,930	86,073	86,137	0.58%	502	86,639	0	86,639
Sep-14	328,970	0.02%	66	84,129	10,813	94,942	95,008	0.58%	554	95,562	0	95,562
Oct-14	443,803	0.02%	89	114,664	51,446	166,111	166,199	0.58%	970	167,169	0	167,169
Peak	5,405,250	0.02%	1,081	2,789,116	0	2,789,116	2,790,197	0.58%	16,278	2,806,475	994,900	3,801,375
Off-Peak	2,115,778	0.02%	423	656,679	0	656,679	657,102	0.58%	3,834	660,936	0	660,936
Annual	7,521,028	0.02%	1,504	3,445,795	0	3,445,795	3,447,299	0.58%	20,112	3,467,411	994,900	4,462,311

	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
BTU Factor	1.043	1.046	1.029	1.05	1.042	1.037	1.041	1.042	1.044	1.039	1.03975	1.038
GSG Meter Throughput (Mcf)	259,715	275,694	259,076	278,578	460,252	528,094	880,611	977,063	812,599	665,946	416,782	312,869
Salem Meter (Mcf)	10,711	11,098	10,145	11,353	21,545	27,009	56,707	61,967	49,058	34,966	18,950	12,766
Total Throughput IN (MCF)	270,427	286,793	269,222	289,932	481,798	555,104	937,319	1,039,031	861,658	700,913	435,733	325,636
GSG Meter Throughput (Dth)	270,883	288,376	266,589	292,507	479,583	547,633	916,716	1,018,100	848,353	691,918	433,349	324,758
Salem Meter (Dth)	11,172	11,609	10,439	11,921	22,450	28,008	59,032	64,570	51,217	36,330	19,703	13,251
Total Throughput IN (Dth)	282,054	299,984	277,028	304,428	502,032	575,642	975,748	1,082,669	899,570	728,248	453,052	338,009
Total Billed Units (MCF)	318,441	289,742	260,613	274,874	373,258	504,178	700,447	1,065,387	908,747	764,228	568,184	385,888
Company Use (MCF)	45	4	1	6	20	36	78	131	113	73	47	24
Current Month Unbilled Units (MCF)	83,561	78,024	65,978	134,517	197,180	254,910	458,003	432,475	399,750	322,410	222,973	108,958
Prior Month Unbilled Units (MCF)	-93,046	-83,561	-78,024	-65,978	-134,517	-197,180	-254,910	-458,003	-432,475	-399,750	-322,410	-222,973
Total Throughput OUT (MCF)	309,001	284,209	248,568	343,419	435,941	561,944	903,618	1,039,990	876,135	686,961	468,794	271,897
Total Billed Units (Dth)	332,134	303,069	268,171	288,617	388,935	522,832	729,165	1,110,134	948,733	794,033	590,769	400,552
Company Use (Dth)	47	5	1	7	21	38	81	137	118	76	49	25
Current Month Unbilled Units (Dth)	87,154	81,615	67,892	141,243	205,461	264,341	476,781	450,639	417,339	334,984	231,836	113,098
Prior Month Unbilled Units (Dth)	-98,443	-87,154	-81,615	-67,892	-141,243	-205,461	-264,341	-476,781	-450,639	-417,339	-334,984	-231,836
Total Throughput OUT (Dth)	320,892	297,534	254,449	361,975	453,174	581,750	941,685	1,084,129	915,550	711,754	487,670	281,839
Total Throughput IN (Dth)	282,054	299,984	277,028	304,428	502,032	575,642	975,748	1,082,669	899,570	728,248	453,052	338,009
Total Throughput OUT (Dth)	320,892	297,534	254,449	361,975	453,174	581,750	941,685	1,084,129	915,550	711,754	487,670	281,839
LAUF	-38,838	2,450	22,579	-57,547	48,859	-6,108	34,063	-1,460	-15,980	16,494	-34,617	56,170
Company Use (Dth)	47	5	1	7	21	38	81	137	118	76	49	25
Company Gas Allowance	-38,791	2,455	22,580	-57,541	48,879	-6,070	34,143	-1,323	-15,863	16,570	-34,568	56,195
LAUF %	-13.77%	0.82%	8.15%	-18.90%	9.73%	-1.06%	3.49%	-0.13%	-1.78%	2.26%	-7.64%	16.62%
Company Use %	0.02%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Company Gas Allowance %	-13.75%	0.82%	8.15%	-18.90%	9.74%	-1.05%	3.50%	-0.12%	-1.76%	2.28%	-7.63%	16.63%

	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11
BTU Factor	1.039	1.033	1.036	1.039	1.041	1.039	1.039	1.046	1.049	1.048	1.041	1.027
GSG Meter Throughput (Mcf)	265,598	249,025	269,606	273,645	427,825	569,708	849,169	1,045,428	914,419	780,093	493,361	356,512
Salem Meter (Mcf)	9,904	9,385	9,959	10,496	18,586	31,154	57,324	67,178	57,567	45,512	25,940	16,128
Total Throughput IN (MCF)	275,503	258,411	279,566	284,142	446,412	600,863	906,494	1,112,607	971,987	825,606	519,302	372,641
GSG Meter Throughput (Dth)	275,956	257,243	279,312	284,317	445,366	591,927	882,287	1,093,518	959,226	817,537	513,589	366,138
Salem Meter (Dth)	10,290	9,695	10,318	10,905	19,348	32,369	59,560	70,268	60,388	47,697	27,004	16,563
Total Throughput IN (Dth)	286,247	266,938	289,629	295,222	464,714	624,296	941,846	1,163,786	1,019,613	865,234	540,592	382,701
Total Billed Units (MCF)	293,685	263,021	273,467	283,785	341,331	501,994	754,087	1,025,592	1,045,825	886,534	679,479	438,668
Company Use (MCF)	6	2	2	5	16	36	82	139	135	99	73	30
Current Month Unbilled Units (MCF)	93,201	89,302	109,507	131,638	205,743	284,516	489,204	531,639	405,881	527,570	309,655	215,425
Prior Month Unbilled Units (MCF)	-108,958	-93,201	-89,302	-109,507	-131,638	-205,743	-284,516	-489,204	-531,639	-405,881	-527,570	-309,655
Total Throughput OUT (MCF)	277,934	259,124	293,674	305,921	415,452	580,803	958,857	1,068,166	920,202	1,008,322	461,637	344,468
Total Billed Units (Dth)	305,139	271,701	283,312	294,853	355,325	521,571	783,495	1,072,769	1,097,070	929,087	707,337	450,512
Company Use (Dth)	7	2	2	6	17	37	85	145	141	104	76	31
Current Month Unbilled Units (Dth)	96,836	92,248	113,449	136,772	214,178	295,613	508,283	556,095	425,769	552,893	322,351	221,241
Prior Month Unbilled Units (Dth)	-113,098	-96,836	-92,248	-113,449	-136,772	-214,178	-295,613	-508,283	-556,095	-425,769	-552,893	-322,351
Total Throughput OUT (Dth)	288,884	267,115	304,514	318,182	432,747	603,043	996,250	1,120,725	966,885	1,056,314	476,871	349,433
Total Throughput IN (Dth)	286,247	266,938	289,629	295,222	464,714	624,296	941,846	1,163,786	1,019,613	865,234	540,592	382,701
Total Throughput OUT (Dth)	288,884	267,115	304,514	318,182	432,747	603,043	996,250	1,120,725	966,885	1,056,314	476,871	349,433
LAUF	-2,637	-178	-14,885	-22,959	31,966	21,252	-54,404	43,060	52,728	-191,080	63,721	33,268
Company Use (Dth)	7	2	2	6	17	37	85	145	141	104	76	31
Company Gas Allowance	-2,631	-176	-14,883	-22,954	31,983	21,289	-54,319	43,205	52,869	-190,977	63,797	33,299
LAUF %	-0.92%	-0.07%	-5.14%	-7.78%	6.88%	3.40%	-5.78%	3.70%	5.17%	-22.08%	11.79%	8.69%
Company Use %	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Company Gas Allowance %	-0.92%	-0.07%	-5.14%	-7.78%	6.88%	3.41%	-5.77%	3.71%	5.19%	-22.07%	11.80%	8.70%

	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12
BTU Factor	1.043	1.039	1.038	1.041	1.042	1.047	1.037	1.032	1.03	1.035	1.028	1.029
GSG Meter Throughput (Mcf)	270,436	244,612	266,618	284,943	411,448	528,465	774,469	924,402	771,024	625,991	456,655	353,621
Salem Meter (Mcf)	11,573	9,849	10,962	11,554	20,294	28,517	46,797	58,942	47,478	34,494	21,251	14,628
Total Throughput IN (MCF)	282,010	254,462	277,581	296,498	431,743	556,983	821,267	983,345	818,503	660,486	477,907	368,250
GSG Meter Throughput (Dth)	282,065	254,152	276,749	296,626	428,729	553,303	803,124	953,983	794,155	647,901	469,441	363,876
Salem Meter (Dth)	12,071	10,233	11,379	12,028	21,146	29,857	48,528	60,828	48,902	35,701	21,846	15,052
Total Throughput IN (Dth)	294,135	264,385	288,128	308,653	449,875	583,160	851,653	1,014,811	843,057	683,602	491,287	378,928
Total Billed Units (MCF)	326,626	267,428	267,015	293,619	328,407	504,624	638,201	916,302	878,240	773,119	555,475	417,161
Company Use (MCF)	28	21	20	27	98	111	160	266	301	240	173	87
Current Month Unbilled Units (MCF)	181,909	126,082	159,356	163,781	276,999	360,970	515,648	516,679	512,139	406,368	230,049	148,767
Prior Month Unbilled Units (MCF)	-215,425	-181,909	-126,082	-159,356	-163,781	-276,999	-360,970	-515,648	-516,679	-512,139	-406,368	-230,049
Total Throughput OUT (MCF)	293,138	211,622	300,309	298,071	441,723	588,706	793,039	917,599	874,001	667,588	379,329	335,966
Total Billed Units (Dth)	340,671	277,859	277,161	305,657	342,200	528,341	661,814	945,625	904,587	800,178	571,029	429,260
Company Use (Dth)	29	22	21	28	102	116	166	274	310	248	178	90
Current Month Unbilled Units (Dth)	189,731	130,999	165,412	170,496	288,633	377,937	534,727	533,212	527,504	420,590	236,491	153,081
Prior Month Unbilled Units (Dth)	-221,241	-189,731	-130,999	-165,412	-170,496	-288,633	-377,937	-534,727	-533,212	-527,504	-420,590	-236,491
Total Throughput OUT (Dth)	309,190	219,149	311,595	310,769	460,439	617,760	818,769	944,385	899,188	693,512	387,108	345,939
Total Throughput IN (Dth)	294,135	264,385	288,128	308,653	449,875	583,160	851,653	1,014,811	843,057	683,602	491,287	378,928
Total Throughput OUT (Dth)	309,190	219,149	311,595	310,769	460,439	617,760	818,769	944,385	899,188	693,512	387,108	345,939
LAUF	-15,055	45,236	-23,467	-2,116	-10,563	-34,600	32,884	70,426	-56,131	-9,910	104,179	32,989
Company Use (Dth)	29	22	21	28	102	116	166	274	310	248	178	90
Company Gas Allowance	-15,026	45,258	-23,446	-2,088	-10,462	-34,484	33,049	70,700	-55,821	-9,662	104,357	33,078
LAUF %	-5.12%	17.11%	-8.14%	-0.69%	-2.35%	-5.93%	3.86%	6.94%	-6.66%	-1.45%	21.21%	8.71%
Company Use %	0.01%	0.01%	0.01%	0.01%	0.02%	0.02%	0.02%	0.03%	0.04%	0.04%	0.04%	0.02%
Company Gas Allowance %	-5.11%	17.12%	-8.14%	-0.68%	-2.33%	-5.91%	3.88%	6.97%	-6.62%	-1.41%	21.24%	8.73%

	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13
BTU Factor	1.031	1.032	1.031	1.029	1.031	1.027	1.031	1.034	1.026	1.024	1.025	1.029
GSG Meter Throughput (Mcf)	305,807	274,541	291,876	300,897	396,348	685,674	783,117	1,020,632	899,906	809,744	554,200	384,902
Salem Meter (Mcf)	11,332	10,022	10,329	11,898	18,768	39,103	52,707	66,624	58,701	49,074	27,692	15,702
Total Throughput IN (MCF)	317,140	284,564	302,206	312,796	415,117	724,778	835,825	1,087,257	958,608	858,819	581,893	400,605
GSG Meter Throughput (Dth)	315,287	283,326	300,924	309,623	408,635	704,187	807,394	1,055,333	923,304	829,178	568,055	396,064
Salem Meter (Dth)	11,683	10,343	10,649	12,243	19,350	40,159	54,341	68,889	60,227	50,252	28,384	16,157
Total Throughput IN (Dth)	326,970	293,669	311,573	321,866	427,985	744,346	861,735	1,124,223	983,531	879,430	596,439	412,222
Total Billed Units (MCF)	337,685	290,872	293,154	294,788	350,451	535,061	778,077	968,852	1,048,985	906,050	697,596	470,412
Company Use (MCF)	67	75	148	166	107	111	211	254	313	279	205	104
Current Month Unbilled Units (MCF)	117,991	126,762	132,561	163,165	202,483	332,362	638,798	733,208	542,597	560,743	335,281	217,281
Prior Month Unbilled Units (MCF)	-148,767	-117,991	-126,762	-132,561	-163,165	-202,483	-332,362	-638,798	-733,208	-542,597	-560,743	-335,281
Total Throughput OUT (MCF)	306,976	299,718	299,101	325,558	389,876	665,051	1,084,724	1,063,516	858,687	924,475	472,339	352,516
Total Billed Units (Dth)	348,153	300,179	302,241	303,338	361,315	549,507	802,198	1,001,792	1,076,260	927,794	715,036	484,053
Company Use (Dth)	69	77	153	171	110	114	218	263	321	286	210	107
Current Month Unbilled Units (Dth)	121,649	130,819	136,670	167,896	208,760	341,336	658,601	758,136	556,705	574,201	343,664	223,581
Prior Month Unbilled Units (Dth)	-153,081	-121,649	-130,819	-136,670	-167,896	-208,760	-341,336	-658,601	-758,136	-556,705	-574,201	-343,664
Total Throughput OUT (Dth)	316,790	309,426	308,245	334,736	402,289	682,197	1,119,680	1,101,591	875,150	945,576	484,710	364,077
Total Throughput IN (Dth)	326,970	293,669	311,573	321,866	427,985	744,346	861,735	1,124,223	983,531	879,430	596,439	412,222
Total Throughput OUT (Dth)	316,790	309,426	308,245	334,736	402,289	682,197	1,119,680	1,101,591	875,150	945,576	484,710	364,077
LAUF	10,180	-15,757	3,328	-12,870	25,696	62,149	-257,946	22,632	108,381	-66,146	111,729	48,145
Company Use (Dth)	69	77	153	171	110	114	218	263	321	286	210	107
Company Gas Allowance	10,249	-15,680	3,482	-12,699	25,806	62,263	-257,728	22,895	108,702	-65,860	111,940	48,252
LAUF %	3.11%	-5.37%	1.07%	-4.00%	6.00%	8.35%	-29.93%	2.01%	11.02%	-7.52%	18.73%	11.68%
Company Use %	0.02%	0.03%	0.05%	0.05%	0.03%	0.02%	0.03%	0.02%	0.03%	0.03%	0.04%	0.03%
Company Gas Allowance %	3.13%	-5.34%	1.12%	-3.95%	6.03%	8.36%	-29.91%	2.04%	11.05%	-7.49%	18.77%	11.71%

	48-Month
BTU Factor	**1.037**
GSG Meter Throughput (Mcf)	**25,241,996**
Salem Meter (Mcf)	**1,373,699**
Total Throughput IN (MCF)	**26,615,745**
GSG Meter Throughput (Dth)	**26,170,593**
Salem Meter (Dth)	**1,424,354**
Total Throughput IN (Dth)	**27,594,947**
Total Billed Units (MCF)	**26,339,655**
Company Use (MCF)	**4,775**
Current Month Unbilled Units (MCF)	**13,853,999**
Prior Month Unbilled Units (MCF)	**-13,729,764**
Total Throughput OUT (MCF)	**26,468,665**
Total Billed Units (Dth)	**27,305,563**
Company Use (Dth)	**4,936**
Current Month Unbilled Units (Dth)	**14,358,941**
Prior Month Unbilled Units (Dth)	**-14,233,802**
Total Throughput OUT (Dth)	**27,435,638**
Total Throughput IN (Dth)	**27,594,947**
Total Throughput OUT (Dth)	**27,435,638**
LAUF	**159,309**
Company Use (Dth)	**4,936**
Company Gas Allowance	**164,246**
LAUF %	**0.58%**
Company Use %	**0.02%**
Company Gas Allowance %	**0.60%**

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**
2	**Total Therms**								
3	Res Heat	381,486	394,202	394,202	356,054	394,202	381,486	4,632,800	2,301,632
4	Res General	14,268	14,744	14,744	13,317	14,744	14,268	173,272	86,084
5	G50 Low Annual-Low Winter	77,431	80,012	80,012	72,269	80,012	69,607	932,501	459,341
6	G40 Low Annual-High Winter	122,409	126,489	126,489	114,248	126,489	122,409	1,486,542	738,532
7	G51 Med Annual-Low Winter	93,669	96,792	96,792	87,425	96,792	93,669	1,137,528	565,138
8	G41 Med Annual-High Winter	105,311	108,821	108,821	98,290	108,821	105,311	1,278,904	635,375
9	G52 High Annual-Low Winter	7,933	8,198	8,198	7,405	8,198	7,933	96,344	47,865
10	G42 High Annual-High Winter	18,008	18,608	18,608	16,807	18,608	18,008	218,686	108,646
11	Total Firm Sales	820,515	847,865	847,865	765,814	847,865	812,691	9,956,578	4,942,614
12	**% of Total**								
13	Res Heat	46.49%	46.49%	46.49%	46.49%	46.49%	46.94%		
14	Res General	1.74%	1.74%	1.74%	1.74%	1.74%	1.76%		
15	G50 Low Annual-Low Winter	9.44%	9.44%	9.44%	9.44%	9.44%	8.57%		
16	G40 Low Annual-High Winter	14.92%	14.92%	14.92%	14.92%	14.92%	15.06%		
17	G51 Med Annual-Low Winter	11.42%	11.42%	11.42%	11.42%	11.42%	11.53%		
18	G41 Med Annual-High Winter	12.83%	12.83%	12.83%	12.83%	12.83%	12.96%		
19	G52 High Annual-Low Winter	0.97%	0.97%	0.97%	0.97%	0.97%	0.98%		
20	G42 High Annual-High Winter	2.19%	2.19%	2.19%	2.19%	2.19%	2.22%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**
23	TOTAL BASE COMMODITY Excld Hedging	$ 456,275	$ 469,927	$ 507,071	$ 457,368	$ 503,044	$ 340,436	$ 4,795,463	$ 2,734,121
24	Res Heat	$ 212,138	$ 218,486	$ 235,755	$ 212,647	$ 233,883	$ 159,804	$ 2,231,103	$ 1,272,713
25	Res General	$ 7,934	$ 8,172	$ 8,818	$ 7,953	$ 8,747	$ 5,977	$ 83,446	$ 47,601
26	G50 Low Annual-Low Winter	$ 43,058	$ 44,346	$ 47,852	$ 43,161	$ 47,471	$ 29,158	$ 449,572	$ 255,047
27	G40 Low Annual-High Winter	$ 68,069	$ 70,106	$ 75,648	$ 68,233	$ 75,047	$ 51,277	$ 715,901	$ 408,380
28	G51 Med Annual-Low Winter	$ 52,088	$ 53,647	$ 57,887	$ 52,213	$ 57,427	$ 39,238	$ 547,820	$ 312,499
29	G41 Med Annual-High Winter	$ 58,562	$ 60,314	$ 65,081	$ 58,702	$ 64,564	$ 44,115	$ 615,905	$ 351,338
30	G52 High Annual-Low Winter	$ 4,412	$ 4,544	$ 4,903	$ 4,422	$ 4,864	$ 3,323	$ 46,398	$ 26,467
31	G42 High Annual-High Winter	$ 10,014	$ 10,313	$ 11,129	$ 10,038	$ 11,040	$ 7,543	$ 105,317	$ 60,077
32									
33	Residential	$ 220,072	$ 226,657	$ 244,573	$ 220,600	$ 242,630	$ 165,781	$ 2,314,548	$ 1,320,314
34	SALES HLF CLASSES	$ 99,558	$ 102,536	$ 110,641	$ 99,796	$ 109,762	$ 71,720	$ 1,043,791	$ 594,013
35	SALES LLF CLASSES	$ 136,645	$ 140,733	$ 151,857	$ 136,972	$ 150,651	$ 102,935	$ 1,437,123	$ 819,794

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**							**Annual**	**Winter**
37	TOTAL BASE HEDGING COMMODITY	$ 3,835	$ 6,006	$ 8,689	$ 7,836	$ 5,884	$ 3,326	$ 35,576	$ 35,576
38	Res Heat	$ 1,783	$ 2,793	$ 4,040	$ 3,643	$ 2,735	$ 1,561	$ 16,555	$ 16,555
39	Res General	$ 67	$ 104	$ 151	$ 136	$ 102	$ 58	$ 619	$ 619
40	G50 Low Annual-Low Winter	$ 362	$ 567	$ 820	$ 739	$ 555	$ 285	$ 3,328	$ 3,328
41	G40 Low Annual-High Winter	$ 572	$ 896	$ 1,296	$ 1,169	$ 878	$ 501	$ 5,312	$ 5,312
42	G51 Med Annual-Low Winter	$ 438	$ 686	$ 992	$ 895	$ 672	$ 383	$ 4,065	$ 4,065
43	G41 Med Annual-High Winter	$ 492	$ 771	$ 1,115	$ 1,006	$ 755	$ 431	$ 4,570	$ 4,570
44	G52 High Annual-Low Winter	$ 37	$ 58	$ 84	$ 76	$ 57	$ 32	$ 344	$ 344
45	G42 High Annual-High Winter	$ 84	$ 132	$ 191	$ 172	$ 129	$ 74	$ 781	$ 781
46									
47	Residential	$ 1,850	$ 2,897	$ 4,191	$ 3,779	$ 2,838	$ 1,620	$ 17,175	$ 17,175
48	SALES HLF CLASSES	$ 837	$ 1,311	$ 1,896	$ 1,710	$ 1,284	$ 701	$ 7,737	$ 7,737
49	SALES LLF CLASSES	$ 1,149	$ 1,799	$ 2,602	$ 2,347	$ 1,762	$ 1,006	$ 10,664	$ 10,664

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	Sum LN 13 : LN 20

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 37 * LN 13
39	Res General	LN 37 * LN 14
40	G50 Low Annual-Low Winter	LN 37 * LN 15
41	G40 Low Annual-High Winter	LN 37 * LN 16
42	G51 Med Annual-Low Winter	LN 37 * LN 17
43	G41 Med Annual-High Winter	LN 37 * LN 18
44	G52 High Annual-Low Winter	LN 37 * LN 19
45	G42 High Annual-High Winter	LN 37 * LN 20
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-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter
51	**Total Therms**								
52	Res Heat	1,381,832	2,203,429	2,885,156	2,385,430	1,719,220	864,060	12,180,882	11,439,126
53	Res General	16,540	30,641	42,551	34,581	22,181	7,493	181,729	153,986
54	G50 Low Annual-Low Winter	21,112	65,157	103,255	80,939	38,097	-	459,114	308,560
55	G40 Low Annual-High Winter	743,102	1,148,539	1,483,159	1,231,388	910,868	488,958	6,244,024	6,006,014
56	G51 Med Annual-Low Winter	48,424	112,533	167,469	133,492	73,514	6,700	724,261	542,132
57	G41 Med Annual-High Winter	467,571	735,120	956,605	792,387	577,806	299,353	4,033,606	3,828,841
58	G52 High Annual-Low Winter	19,236	31,827	42,331	34,837	24,366	11,258	179,282	163,857
59	G42 High Annual-High Winter	83,149	130,410	169,519	140,463	102,633	53,446	714,633	679,620
60	Total Firm Sales	2,780,965	4,457,655	5,850,045	4,833,516	3,468,685	1,731,269	24,717,532	23,122,136
61	**% of Total**								
62	Res Heat	49.69%	49.43%	49.32%	49.35%	49.56%	49.91%		
63	Res General	0.59%	0.69%	0.73%	0.72%	0.64%	0.43%		
64	G50 Low Annual-Low Winter	0.76%	1.46%	1.77%	1.67%	1.10%	0.00%		
65	G40 Low Annual-High Winter	26.72%	25.77%	25.35%	25.48%	26.26%	28.24%		
66	G51 Med Annual-Low Winter	1.74%	2.52%	2.86%	2.76%	2.12%	0.39%		
67	G41 Med Annual-High Winter	16.81%	16.49%	16.35%	16.39%	16.66%	17.29%		
68	G52 High Annual-Low Winter	0.69%	0.71%	0.72%	0.72%	0.70%	0.65%		
69	G42 High Annual-High Winter	2.99%	2.93%	2.90%	2.91%	2.96%	3.09%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter
72	REMAINING COMMODITY Excld Hedging	$ 1,537,978	$ 2,303,932	$ 3,745,109	$ 2,935,152	$ 1,854,484	$ 729,488	$ 13,781,886	$ 13,106,143
73	Res Heat	$ 764,205	$ 1,138,839	$ 1,847,033	$ 1,448,552	$ 919,157	$ 364,081	$ 6,796,042	$ 6,481,865
74	Res General	$ 9,147	$ 15,837	$ 27,241	$ 20,999	$ 11,859	$ 3,157	$ 99,990	$ 88,239
75	G50 Low Annual-Low Winter	$ 11,676	$ 33,676	$ 66,102	$ 49,150	$ 20,368	$ -	$ 244,741	$ 180,972
76	G40 Low Annual-High Winter	$ 410,963	$ 593,620	$ 949,496	$ 747,760	$ 486,983	$ 206,028	$ 3,495,661	$ 3,394,850
77	G51 Med Annual-Low Winter	$ 26,780	$ 58,162	$ 107,211	$ 81,063	$ 39,303	$ 2,823	$ 392,485	$ 315,343
78	G41 Med Annual-High Winter	$ 258,584	$ 379,945	$ 612,404	$ 481,177	$ 308,916	$ 126,136	$ 2,253,891	$ 2,167,162
79	G52 High Annual-Low Winter	$ 10,638	$ 16,450	$ 27,100	$ 21,155	$ 13,027	$ 4,744	$ 99,648	$ 93,114
80	G42 High Annual-High Winter	$ 45,984	$ 67,402	$ 108,523	$ 85,296	$ 54,871	$ 22,520	$ 399,428	$ 384,598
81									
82	Residential	$ 773,352	$ 1,154,675	$ 1,874,273	$ 1,469,551	$ 931,016	$ 367,238	$ 6,896,032	$ 6,570,105
83	SALES HLF CLASSES	$ 49,094	$ 108,288	$ 200,413	$ 151,368	$ 72,698	$ 7,567	$ 736,874	$ 589,429
84	SALES LLF CLASSES	$ 715,532	$ 1,040,968	$ 1,670,423	$ 1,314,233	$ 850,770	$ 354,683	$ 6,148,980	$ 5,946,609

85	**REMAINING COMMODITY HEDGING COSTS**							Annual	Winter
86	TOTAL REMAINING COMMODITY HEDGING	$ 12,678	$ 23,917	$ 25,554	$ 23,243	$ 16,800	$ 7,025	$ 109,216	$ 109,216
87	Res Heat	$ 6,299	$ 11,822	$ 12,603	$ 11,471	$ 8,327	$ 3,506	$ 54,028	$ 54,028
88	Res General	$ 75	$ 164	$ 186	$ 166	$ 107	$ 30	$ 730	$ 730
89	G50 Low Annual-Low Winter	$ 96	$ 350	$ 451	$ 389	$ 185	$ -	$ 1,471	$ 1,471
90	G40 Low Annual-High Winter	$ 3,388	$ 6,162	$ 6,479	$ 5,921	$ 4,412	$ 1,984	$ 28,346	$ 28,346
91	G51 Med Annual-Low Winter	$ 221	$ 604	$ 732	$ 642	$ 356	$ 27	$ 2,581	$ 2,581
92	G41 Med Annual-High Winter	$ 2,132	$ 3,944	$ 4,179	$ 3,810	$ 2,799	$ 1,215	$ 18,078	$ 18,078
93	G52 High Annual-Low Winter	$ 88	$ 171	$ 185	$ 168	$ 118	$ 46	$ 775	$ 775
94	G42 High Annual-High Winter	$ 379	$ 700	$ 740	$ 675	$ 497	$ 217	$ 3,209	$ 3,209
95								$ -	$ -
96	Residential	$ 6,375	$ 11,987	$ 12,789	$ 11,637	$ 8,434	$ 3,536	$ 54,758	$ 54,758
97	SALES HLF CLASSES	$ 405	$ 1,124	$ 1,367	$ 1,199	$ 659	$ 73	$ 4,826	$ 4,826
98	SALES LLF CLASSES	$ 5,898	$ 10,806	$ 11,398	$ 10,407	$ 7,707	$ 3,416	$ 49,632	$ 49,632

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	Sum LN 62 : LN 69

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 86 * LN 62
88	Res General	LN 86 * LN 63
89	G50 Low Annual-Low Winter	LN 86 * LN 64
90	G40 Low Annual-High Winter	LN 86 * LN 65
91	G51 Med Annual-Low Winter	LN 86 * LN 66
92	G41 Med Annual-High Winter	LN 86 * LN 67
93	G52 High Annual-Low Winter	LN 86 * LN 68
94	G42 High Annual-High Winter	LN 86 * LN 69
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**							**Annual**	**Winter**
100	TOTAL COMMODITY Excld Hedging	$ 1,994,253	$ 2,773,859	$ 4,252,181	$ 3,392,520	$ 2,357,528	$ 1,069,924	$ 18,577,348	$ 15,840,264
101	Res Heat	$ 976,343	$ 1,357,324	$ 2,082,788	$ 1,661,198	$ 1,153,040	$ 523,885	$ 9,027,144	$ 7,754,578
102	Res General	$ 17,081	$ 24,008	$ 36,058	$ 28,952	$ 20,606	$ 9,134	$ 183,436	$ 135,840
103	G50 Low Annual-Low Winter	$ 54,734	$ 78,022	$ 113,954	$ 92,311	$ 67,839	$ 29,158	$ 694,313	$ 436,019
104	G40 Low Annual-High Winter	$ 479,033	$ 663,726	$ 1,025,143	$ 815,993	$ 562,030	$ 257,305	$ 4,211,562	$ 3,803,230
105	G51 Med Annual-Low Winter	$ 78,868	$ 111,809	$ 165,098	$ 133,276	$ 96,730	$ 42,061	$ 940,306	$ 627,842
106	G41 Med Annual-High Winter	$ 317,146	$ 440,259	$ 677,485	$ 539,879	$ 373,480	$ 170,250	$ 2,869,797	$ 2,518,499
107	G52 High Annual-Low Winter	$ 15,050	$ 20,994	$ 32,003	$ 25,577	$ 17,891	$ 8,067	$ 146,046	$ 119,581
108	G42 High Annual-High Winter	$ 55,998	$ 77,716	$ 119,652	$ 95,334	$ 65,911	$ 30,063	$ 504,745	$ 444,675
109									
110	Residential	$ 993,424	$ 1,381,332	$ 2,118,846	$ 1,690,151	$ 1,173,646	$ 533,019	$ 9,210,580	$ 7,890,418
111	SALES HLF CLASSES	$ 148,652	$ 210,825	$ 311,054	$ 251,164	$ 182,461	$ 79,287	$ 1,780,665	$ 1,183,443
112	SALES LLF CLASSES	$ 852,177	$ 1,181,702	$ 1,822,280	$ 1,451,206	$ 1,001,421	$ 457,618	$ 7,586,104	$ 6,766,404

113	**TOTAL HEDGING COMMODITY COSTS**							**Annual**	**Winter**
114	TOTAL HEDGING COMMODITY	$ 16,513	$ 29,923	$ 34,243	$ 31,078	$ 22,684	$ 10,351	$ 144,792	$ 144,792
115	Res Heat	$ 8,083	$ 14,615	$ 16,642	$ 15,114	$ 11,062	$ 5,067	$ 70,583	$ 70,583
116	Res General	$ 142	$ 269	$ 337	$ 303	$ 210	$ 89	$ 1,349	$ 1,349
117	G50 Low Annual-Low Winter	$ 458	$ 916	$ 1,271	$ 1,129	$ 740	$ 285	$ 4,799	$ 4,799
118	G40 Low Annual-High Winter	$ 3,960	$ 7,058	$ 7,775	$ 7,090	$ 5,290	$ 2,485	$ 33,658	$ 33,658
119	G51 Med Annual-Low Winter	$ 659	$ 1,289	$ 1,723	$ 1,536	$ 1,028	$ 411	$ 6,646	$ 6,646
120	G41 Med Annual-High Winter	$ 2,624	$ 4,715	$ 5,294	$ 4,816	$ 3,554	$ 1,646	$ 22,648	$ 22,648
121	G52 High Annual-Low Winter	$ 125	$ 229	$ 269	$ 243	$ 175	$ 78	$ 1,119	$ 1,119
122	G42 High Annual-High Winter	$ 463	$ 832	$ 931	$ 847	$ 626	$ 291	$ 3,990	$ 3,990
123									
124	Residential	$ 8,225	$ 14,884	$ 16,979	$ 15,416	$ 11,272	$ 5,156	$ 71,932	$ 71,932
125	SALES HLF CLASSES	$ 1,242	$ 2,435	$ 3,263	$ 2,908	$ 1,942	$ 774	$ 12,564	$ 12,564
126	SALES LLF CLASSES	$ 7,047	$ 12,605	$ 14,000	$ 12,754	$ 9,469	$ 4,421	$ 60,296	$ 60,296

127	TOTAL COMMODITY	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**
128	Res Heat	$ 984,425	$ 1,371,939	$ 2,099,430	$ 1,676,312	$ 1,164,102	$ 528,952	$ 9,097,728	$ 7,825,161
129	Res General	$ 17,223	$ 24,277	$ 36,395	$ 29,255	$ 20,816	$ 9,223	$ 184,785	$ 137,189
130	G50 Low Annual-Low Winter	$ 55,192	$ 78,939	$ 115,225	$ 93,440	$ 68,579	$ 29,443	$ 699,112	$ 440,818
131	G40 Low Annual-High Winter	$ 482,993	$ 670,785	$ 1,032,918	$ 823,083	$ 567,319	$ 259,790	$ 4,245,220	$ 3,836,888
132	G51 Med Annual-Low Winter	$ 79,527	$ 113,098	$ 166,821	$ 134,812	$ 97,758	$ 42,472	$ 946,952	$ 634,488
133	G41 Med Annual-High Winter	$ 319,770	$ 444,974	$ 682,779	$ 544,695	$ 377,034	$ 171,896	$ 2,892,445	$ 2,541,147
134	G52 High Annual-Low Winter	$ 15,175	$ 21,222	$ 32,272	$ 25,820	$ 18,066	$ 8,145	$ 147,165	$ 120,700
135	G42 High Annual-High Winter	$ 56,461	$ 78,547	$ 120,583	$ 96,182	$ 66,538	$ 30,354	$ 508,735	$ 448,665
136	Total Firm Sales	$ 2,010,766	$ 2,803,782	$ 4,286,423	$ 3,423,599	$ 2,380,212	$ 1,080,275	$ 18,722,140	$ 15,985,057
137									
138	Residential	$ 1,001,649	$ 1,396,216	$ 2,135,826	$ 1,705,567	$ 1,184,918	$ 538,175	$ 9,282,512	$ 7,962,351
139	SALES HLF CLASSES	$ 149,894	$ 213,260	$ 314,317	$ 254,072	$ 184,403	$ 80,060	$ 1,793,228	$ 1,196,006
140	SALES LLF CLASSES	$ 859,224	$ 1,194,307	$ 1,836,280	$ 1,463,959	$ 1,010,891	$ 462,039	$ 7,646,400	$ 6,826,699
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								14.91%
144	SALES LLF CLASSES								85.09%

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)

Schedules 11A, 11B, 11C,11D & 11E

Northern Utilities, Inc.
New Hampshire Division
Schedule 11A
Page 1 of 1

Northern Utilities, Inc.
Normal Weather - Sales Service & Company Managed Sendout
Commodity Volumes by Supply Source (Dth)
November 2013 through April 2014

Description	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Season
Pipeline Supplies							
Tennessee Production	150,505	254,277	153,727	139,483	131,970	317,857	1,147,820
Chicago	170,113	179,674	179,674	162,286	179,746	0	871,493
Algonquin Receipts	37,530	38,781	38,781	35,028	38,781	0	188,901
TGP Zone 6	0	0	0	0	0	56,894	56,894
Niagara	58,317	63,433	63,433	57,294	60,261	44,454	347,191
Iroquois Receipts	16,506	19,688	19,688	17,783	13,094	0	86,760
PNGTS	26,906	27,802	27,802	25,112	27,802	0	135,424
PNGTS Delivered	26,906	27,802	27,802	25,112	27,802	0	135,424
Lewiston Baseload	195,000	201,500	201,500	182,000	201,500	45,000	1,026,500
Subtotal Pipeline	681,783	812,958	712,408	644,098	680,957	464,205	3,996,408
Underground Storage							
Tenn Zone 4 Spot	64,149	73,586	0	0	17,090	69,929	224,755
Tennessee Storage	0	0	73,653	66,525	53,263	0	193,442
Tennesse Storage Path	64,149	73,586	73,653	66,525	70,353	69,929	418,196
W10 AMA Spot	0	0	0	0	0	0	0
Washington 10 Storage	79,127	511,569	862,338	721,994	373,774	0	2,548,803
W10 Storage Path	79,127	511,569	862,338	721,994	373,774	0	2,548,803
Subtotal Storage	143,277	585,155	935,992	788,519	444,127	69,929	2,966,999
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	155,481	93,644	0	0	249,125
LNG	1,350	1,395	1,395	1,260	1,395	3,065	9,860
Subtotal Peaking	1,350	1,395	156,876	94,904	1,395	3,065	258,985
Total Delivered (Dth)	826,409	1,399,508	1,805,275	1,527,522	1,126,479	537,199	7,222,392

Northern Utilities, Inc.
Design Cold Winter Weather - Sales Service & Company Managed Sendout
Commodity Volumes by Supply Source (Dth)
November 2013 through April 2014

Description	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Season
Pipeline Supplies							
Tennessee Production	227,333	289,318	269,176	224,505	193,086	313,298	1,516,716
Chicago	174,164	179,674	179,674	162,286	179,746	0	875,545
Algonquin Receipts	37,530	38,781	38,781	35,028	38,781	0	188,901
TGP Zone 6	0	0	0	0	0	36,017	36,017
Niagara	58,317	63,433	63,433	57,294	60,261	39,380	342,117
Iroquois Receipts	12,455	19,688	19,688	17,783	13,094	0	82,709
PNGTS	26,906	27,802	27,802	25,112	27,802	0	135,424
PNGTS Delivered	26,906	27,802	27,802	25,112	27,802	0	135,424
Lewiston Baseload	195,000	201,500	201,500	182,000	201,500	45,000	1,026,500
Subtotal Pipeline	758,610	847,998	827,857	729,120	742,072	433,695	4,339,353
Underground Storage							
Tenn Zone 4 Spot	68,000	73,653	0	0	20,391	69,799	231,842
Tennessee Storage	0	0	73,653	66,525	53,263	0	193,442
Tennesse Storage Path	68,000	73,653	73,653	66,525	73,653	69,799	425,284
W10 AMA Spot	0	0	0	0	0	0	0
Washington 10 Storage	101,188	661,912	916,582	845,309	409,759	0	2,934,749
W10 Storage Path	101,188	661,912	916,582	845,309	409,759	0	2,934,749
Subtotal Storage	169,188	735,565	990,235	911,834	483,412	69,799	3,360,033
Peaking Supplies							
Peaking Supply 1	0	47,057	50,065	0	5,072	0	102,194
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	5,807	214,189	29,129	0	0	249,125
LNG	1,350	1,395	1,395	1,260	3,110	1,350	9,860
Subtotal Peaking	1,350	54,259	265,649	30,389	8,182	1,350	361,179
Total Delivered (Dth)	929,148	1,637,823	2,083,741	1,671,343	1,233,667	504,844	8,060,565

Northern Utilities, Inc.
Normal Weather - Sales Service & Company Managed Sendout
Capacity Utilization by Supply Source
November 2013 through April 2014

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Tennessee Production	1,147,820	2,086,578	55%
Chicago Path (includes Iroquois Receipts)	958,254	1,164,554	82%
Algonquin Receipts	188,901	226,431	83%
TGP Zone 6	56,894	0	
Niagara	347,191	421,187	82%
PNGTS	135,424	174,452	78%
PNGTS Delivered	135,424	135,447	100%
Lewiston Baseload	1,026,500	1,026,500	100%
Subtotal Pipeline	3,996,408	5,235,149	76%
Underground Storage			
Tenn Zone 4 Spot	224,755		
Tennessee Storage	193,442		
Tennesse Storage Path	418,196	430,039	97%
W10 AMA Spot	0		
Washington 10 Storage	2,548,803		
W10 Storage Path	2,548,803	4,965,635	51%
Subtotal Storage	2,966,999	5,395,674	55%
Peaking Supplies			
Peaking Supply 1	0	224,220	0%
Peaking Supply 2	0	30,000	0%
Peaking Supply 3	249,125	249,130	100%
LNG	9,860	1,810,000	1%
Subtotal Peaking	258,985	2,313,350	11%
Total Delivered (Dth)	7,222,392	12,944,173	56%

Northern Utilities, Inc.
Design Cold Winter Weather - Sales Service & Company Managed Sendout
Capacity Utilization by Supply Source
November 2013 through April 2014

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Tennessee Production	1,516,716	2,086,578	73%
Chicago Path (includes Iroquois Receipts)	958,254	1,164,554	82%
Algonquin Receipts	188,901	226,431	83%
TGP Zone 6	36,017	0	
Niagara	342,117	421,187	81%
PNGTS	135,424	174,452	78%
PNGTS Delivered	135,424	135,447	100%
Lewiston Baseload	1,026,500	1,026,500	100%
Subtotal Pipeline	4,339,353	5,235,149	83%
Underground Storage			
Tenn Zone 4 Spot	231,842		
Tennessee Storage	193,442		
Tennesse Storage Path	425,284	430,039	99%
W10 AMA Spot	0		
Washington 10 Storage	2,934,749		
W10 Storage Path	2,934,749	4,965,635	59%
Subtotal Storage	3,360,033	5,395,674	62%
Peaking Supplies			
Peaking Supply 1	102,194	224,220	46%
Peaking Supply 2	0	30,000	0%
Peaking Supply 3	249,125	249,130	100%
LNG	9,860	1,810,000	1%
Subtotal Peaking	361,179	2,313,350	16%
Total Delivered (Dth)	8,060,565	12,944,173	62%

Northern Utilities Inc.
Forecast of Upcoming Winter Period Design Day Report
2013 / 2014 Winter Period
(Therms)

Demand	
NH Firm Sales	437,810
NH Non-Capacity Exempt Transportation	111,740
NH Capacity Exempt Transportation	128,680
NH Interruptible Sales	0
NH Interruptible Transportation	0
NH Design Day Demand	678,230
ME Firm Sales	401,860
ME Non-Capacity Exempt Transportation	160,000
ME Capacity Exempt Transportation	276,640
ME Interruptible Sales	0
ME Interruptible Transportation	0
ME Design Day Demand	838,500
Total Firm Sales	839,670
Total Non-Capacity Exempt Transportation	271,740
Total Capacity Exempt Transportation	405,320
Total Interruptible Sales	0
Total Interruptible Transportation	0
Total Design Day Demand	1,516,730
Supplies	
Capacity Exempt Transportation	405,320
Pipeline	316,140
Storage	355,290
On-System LNG	100,000
Off-System Peaking	448,610
On-System Propane	0
Total	1,625,360
Effective Degree Day	
New Hampshire	81
Maine	79
Probability	1 in 30

Northern Utilities Inc.
New Hampshire 7 Day Cold Snap Analysis
Winter 2013-2014

Coldest 7 Consecutive Days

Based on historic Portsmouth weather data

Date	EDD
February 11, 1979	68
February 12, 1979	60
February 13, 1979	73
February 14, 1979	73
February 15, 1979	64
February 16, 1979	69
February 17, 1979	72
Total	479

Maximum Projected Design Week Demand (Dth)

Daily Baseload	5,428
Weekly Baseload	37,999
Heating Increment*	570
Effective Degree Days	479
Total Heat Load	272,979
Projected Cold Snap Demand	310,978

** Based on forecasted maximum heating increment in the latest IRP filing.*

New Hampshire Allocation **47.24%**

Based on the latest demand cost allocator in the Winter COG filing.

Maximum Supply Capability (Dth)

Amount to be Supplied by Natural Gas Pipelines	
Tennessee Production	13,109
Chicago City-Gates Supply	6,434
Algonquin Receipt Points Supply	1,251
Niagara	2,327
PNGTS	1,096
PNGTS Delivered	897
Lewiston City-Gate Baseload Supply	6,500
Tennessee Firm Storage	2,644
Washington 10 Storage	32,885
Peaking Supply 1	14,948
Peaking Supply 2	5,000
Peaking Supply 3	24,913
Total Daily Pipeline	112,004
Pipeline for 7 days	784,028
New Hampshire Allocation	370,375

Available LNG Storage

Facility	Gallons	Dth
Lewiston LNG	145,134	12,140
Total	145,134	12,140
New Hampshire Allocation - 7 Days		5,735

LNG Delivery Contract

Northern Utilities plans to secure a contract for LNG Delivery for up to four loads of LNG per day.

The storage credit for LNG is calculated as follows:

Number of Days	5
Number of Loads	4
Delivery Reliability	70%
Assumed Number of LNG Deliveries	14
Dth Per Load	900
Total Storage Credit	12,600
NH Storage Credit - 7 Days	5,952

Summary	
Maximum projected design week demand	310,978
Amount to be furnished by natural gas pipeline	370,375
Remaining Balance	-59,396
Storage available	5,735
Credit from LNG delivery supply contract	5,952
Total available storage and propane deliveries	11,687
Net Surplus/(Deficiency)	**71,084**

Report Prepared By	Francis X. Wells
Title	Manager, Energy Planning
Signature	

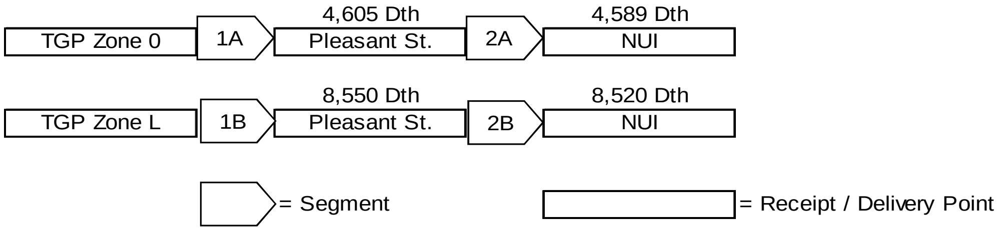
Schedule 12

Northern Capacity by Supply Source (Dth per Day)

Supply Source	2013-2014 Winter	2014 Summer
Tennessee Production	13,109	13,109
Chicago City-Gates Supply	6,434	6,434
Algonquin Receipt Points Supply	1,251	1,251
Niagara	2,327	2,327
PNGTS	1,096	1,096
PNGTS Delivered	897	0
Lewiston City-Gate Baseload Supply	6,500	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Supply 1	14,948	0
Peaking Supply 2	5,000	0
Peaking Supply 3	24,913	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**122,004**	**36,861**

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

Capacity Path Diagram



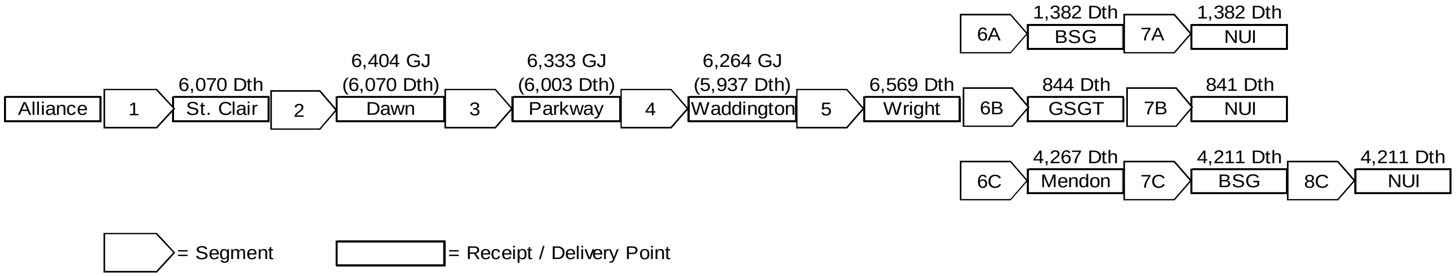
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	Dth				

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

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

Capacity Path Diagram

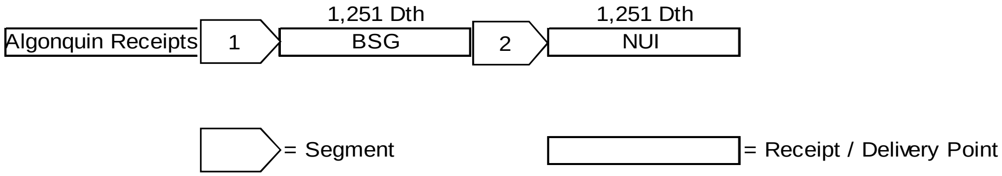


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	Union
3	Transportation	Union	M12205	M12	10/31/2017	6,333	GJ	Year-Round	Dawn	Parkway	TransCanada
4	Transportation	TransCanada	41235	FT	10/31/2017	6,264	GJ	Year-Round	Parkway	Waddington	Iroquois
5	Transportation	Iroquois	R181001	RTS-1	10/31/2017	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
6A	Transportation	Tennessee	95196	FT-A	10/31/2017	1,382	Dth	Year-Round	Wright	Bay State City Gate	
7A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
6B	Transportation	Tennessee	95196	FT-A	10/31/2017	844	Dth	Year-Round	Wright	Pleasant St.	Granite
7B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	841	Dth	Year-Round	Granite	Northern City Gates	
6C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
7C	Transportation	Algonquin	93200F	AFT-1	10/31/2014	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
8C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,434	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Algonquin Receipt Points

Capacity Path Diagram

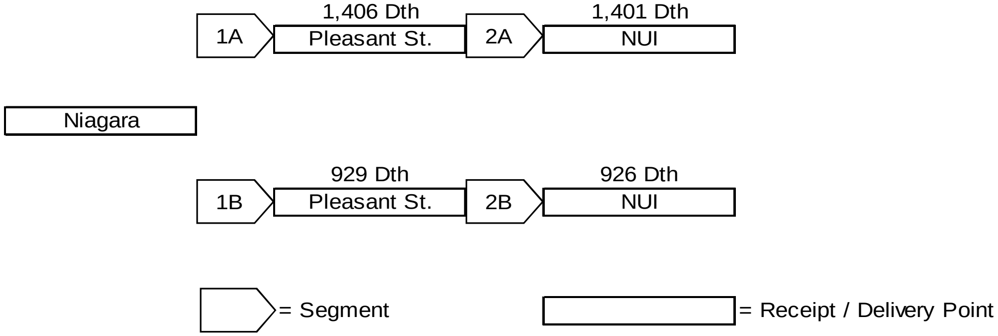


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2014	1,251	Dth	Year-Round	Algonquin Receipt Points	Bay State City Gate	
2	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,251	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						1,251	Dth				

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

Capacity Path Diagram

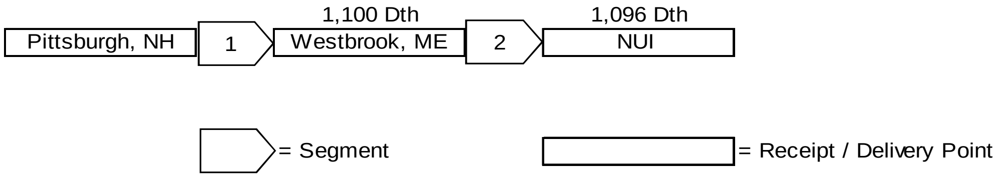


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2015	1,406	Dth	Year-Round	Niagara	Pleasant St.	Granite
2A	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	1,401	Dth	Year-Round	Granite	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2015	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	926	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						2,327	Dth				

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

Capacity Path Diagram

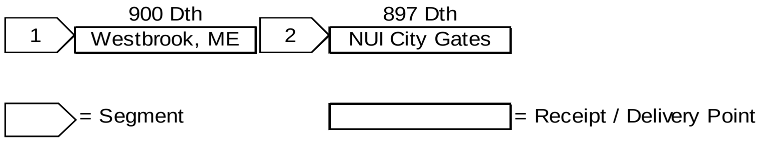


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	1,096	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						1,096	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: PNGTS Delivered Supply

Capacity Path Diagram

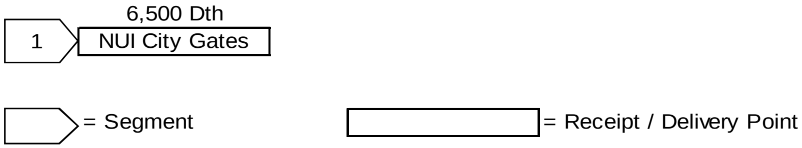


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	PNGTS Supply	Confidential	NA	NA	3/31/2014	900	Dth	Winter Only (Nov - Mar)	NA	Westbrook	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	897	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						897	Dth				

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

Capacity Path Diagram

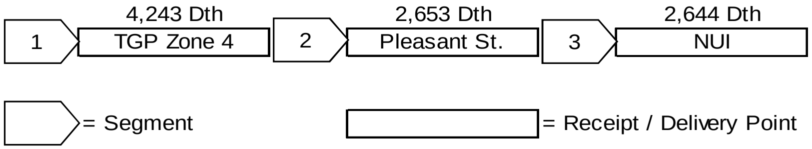


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Delivered Supply	Confidential	NA	NA	3/31/2014	6,500	Dth	NA	NA	Northern City Gate (Lewiston)	NA
Total Path Deliverable						6,500	Dth				

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

Capacity Path Diagram



Capacity Path Detail

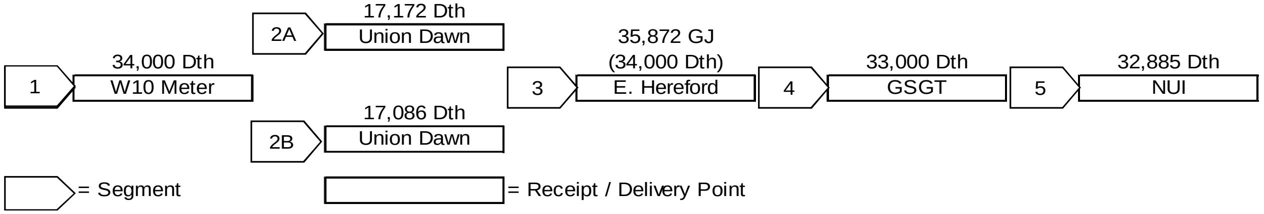
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	3/31/2015	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2015	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

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

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

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

Capacity Path Diagram



Capacity Path Detail

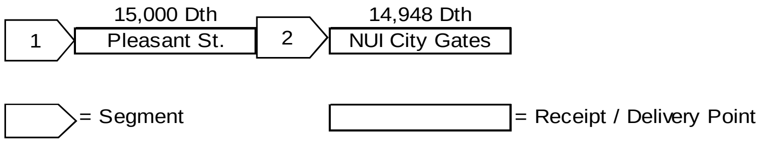
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-0725	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-0727	FT	3/31/2017	17,086	Dth	Winter Only (Nov - Mar)	W10 Withdrawal Meter	Union Dawn	TransCanada
3	Transportation	TransCanada	33322	FT	3/31/2018	35,872	GJ	Year-Round	Union Dawn	East Hereford	PNGTS
4	Transportation	PNGTS	1997-004	FT	3/9/2019	33,000	Dth	Winter Only (Nov - Mar)	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	32,885	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,885	Dth				

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

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

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

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2014	15,000	Dth	Winter Only (Nov - Mar)	NA	Pleasant St.	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	14,948	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						14,948	Dth				

Note 1: Peaking Supply 1 Contract allows Northern to nominate up to 15,000 Dth per Day and up to 225,000 Dth from November 2013 through March 2014.

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

Capacity Path Diagram

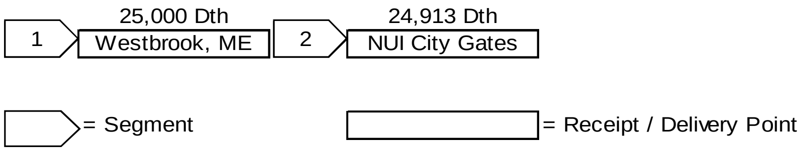
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2014	5,000	Dth	Winter Only (Nov-Mar)	NA	Northern City Gates	Granite
Total Path Deliverable						5,000	Dth				

Note 1: Peaking Supply 2 Contract allows Northern to nominate up to 5,000 Dth per Day and up to 30,000 Dth from November 2013 through March 2014.

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

Capacity Path Diagram



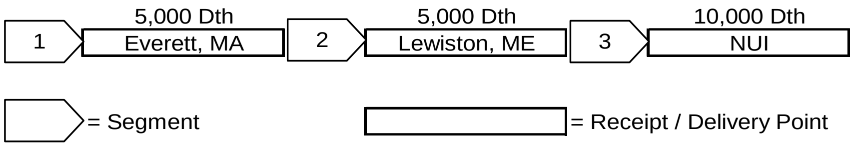
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2013	25,000	Dth	Winter Only (Dec-Feb)	NA	Westbrook, ME	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	24,913	Dth	Year-Round	Westbrook, ME	Northern City Gates	
Total Path Deliverable						24,913	Dth				

Note 1: Peaking Supply 3 Contract allows Northern to nominate up to 25,000 Dth per Day and up to 250,000 Dth from November 2013 through March 2014.

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

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	LNG Contract	Confidential	NA	NA	10/31/2013	5,000	Dth	Year-Round	NA	Everett, MA	NA
2	LNG Trucking Contract	Confidential			10/31/2013	5,000	Dth	Year-Round	Everett, MA	Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	10,000	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						10,000	Dth				

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

Schedule 13

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2013 through October 2014

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	768,250	44%	80%
G50	138,285	8%	74%
G41	527,943	30%	44%
G51	185,008	11%	40%
G42	92,751	5%	18%
G52	27,391	2%	2%
Special Contracts	-	0%	0%
Total C&I	1,739,628	100%	30%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
T40	193,881	5%	20%
T50	48,285	1%	26%
T41	671,735	16%	56%
T51	282,987	7%	60%
T42	423,535	10%	82%
T52	1,444,373	35%	98%
Special Contracts	1,010,437	25%	100%
Total C&I	4,075,233	100%	70%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G/T40	962,131	17%
G/T50	186,570	3%
G/T41	1,199,678	21%
G/T51	467,995	8%
G/T42	516,286	9%
G/T52	1,471,763	25%
Special Contracts	1,010,437	17%
Total C&I	5,814,860	100%

Schedule 14

Northern Utilities, Inc.
New Hampshire Division
Schedule 14
Page 1 of 1

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-13	196,837	-	-	196,837	$ 734,398	$ 3.73	NA	$ -	$ 3.73	$ -	$ 734,398	2.19%	$ 1,338	$ 734,398	$ -
Dec-13	196,837	-	-	196,837	$ 734,398	$ 3.73	NA	$ -	$ 3.73	$ -	$ 734,398	2.19%	$ 1,338	$ 734,398	$ -
Jan-14	196,837	-	74,946	121,891	$ 734,398	$ 3.73	NA	$ -	$ 3.73	$ 279,624	$ 454,774	2.19%	$ 1,083	$ 454,774	$ 279,624
Feb-14	121,891	-	67,693	54,198	$ 454,774	$ 3.73	NA	$ -	$ 3.73	$ 252,563	$ 202,211	2.19%	$ 598	$ 202,211	$ 252,563
Mar-14	54,198	-	54,198	-	$ 202,211	$ 3.73	NA	$ -	$ 3.73	$ 202,211	$ -	2.19%	$ 184	$ -	$ 202,211
Apr-14	-	-	-	-	$ -	NA	NA	$ -	$ -	$ -	$ -	2.19%	$ -	$ -	$ -
May-14	-	40,682	-	40,682	-	NA	$ 3.73	$ 151,692	$ 3.73	$ -	$ 151,692	2.19%	$ 138	$ 151,692	$ -
Jun-14	40,682	39,369	-	80,051	$ 151,692	$ 3.73	$ 3.76	$ 148,083	$ 3.74	$ -	$ 299,775	2.19%	$ 411	$ 299,775	$ -
Jul-14	80,051	40,682	-	120,733	$ 299,775	$ 3.74	$ 3.80	$ 154,388	$ 3.76	$ -	$ 454,162	2.19%	$ 687	$ 454,162	$ -
Aug-14	120,733	38,057	-	158,790	$ 454,162	$ 3.76	$ 3.81	$ 145,048	$ 3.77	$ -	$ 599,210	2.19%	$ 960	$ 599,209	$ -
Sep-14	158,790	38,047	-	196,837	$ 599,210	$ 3.77	$ 3.81	$ 145,010	$ 3.78	$ -	$ 744,220	2.19%	$ 1,224	$ 744,219	$ -
Oct-14	196,837	-	-	196,837	$ 744,220	$ 3.78	NA	$ -	$ 3.78	$ -	$ 744,220	2.19%	$ 1,356	$ 744,219	$ -

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-13	3,400,000	-	81,189	3,318,811	$13,147,800	$ 3.87	NA	$ -	$ 3.87	$ 313,959	$ 12,833,841	2.19%		$ 12,833,841	$ 313,959
Dec-13	3,318,811	-	524,903	2,793,907	$12,833,841	$ 3.87	NA	$ -	$ 3.87	$2,029,801	$ 10,804,040	2.19%		$ 10,804,040	$2,029,801
Jan-14	2,793,907	-	884,815	1,909,092	$10,804,040	$ 3.87	NA	$ -	$ 3.87	$3,421,581	$ 7,382,458	2.19%		$ 7,382,458	$3,421,581
Feb-14	1,909,092	-	740,813	1,168,279	$ 7,382,458	$ 3.87	NA	$ -	$ 3.87	$2,864,725	$ 4,517,733	2.19%		$ 4,517,733	$2,864,725
Mar-14	1,168,279	-	383,517	784,762	$ 4,517,733	$ 3.87	NA	$ -	$ 3.87	$1,483,060	$ 3,034,673	2.19%		$ 3,034,673	$1,483,060
Apr-14	784,762	455,076	-	1,239,838	$ 3,034,673	$ 3.87	$ 3.88	$1,763,443	$ 3.87	$ -	$ 4,798,116	2.19%		$ 4,798,116	$ -
May-14	1,239,838	470,245	-	1,710,083	$ 4,798,116	$ 3.87	$ 3.90	$1,833,263	$ 3.88	$ -	$ 6,631,379	2.19%		$ 6,631,379	$ -
Jun-14	1,710,083	455,076	-	2,165,159	$ 6,631,379	$ 3.88	$ 3.93	$1,788,988	$ 3.89	$ -	$ 8,420,368	2.19%		$ 8,420,368	$ -
Jul-14	2,165,159	470,245	-	2,635,405	$ 8,420,368	$ 3.89	$ 3.96	$1,864,459	$ 3.90	$ -	$ 10,284,827	2.19%		$ 10,284,827	$ -
Aug-14	2,635,405	385,365	-	3,020,770	$10,284,827	$ 3.90	$ 3.98	$1,534,214	$ 3.91	$ -	$ 11,819,040	2.19%		$ 11,819,040	$ -
Sep-14	3,020,770	379,230	-	3,400,000	$11,819,040	$ 3.91	$ 3.98	$1,509,789	$ 3.92	$ -	$ 13,328,829	2.19%		$ 13,328,829	$ -
Oct-14	3,400,000	-	-	3,400,000	$13,328,829	$ 3.92	NA	$ -	$ 3.92	$ -	$ 13,328,829	2.19%		$ 13,328,829	$ -

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-13	11,250	2,600	1,350	12,500	$ 77,850	$ 6.92	$ 6.10	$ 15,865	$ 6.77	$ 9,135	$ 84,581	2.19%	$ 148	$ 84,581	$ 9,135
Dec-13	12,500	1,395	1,395	12,500	$ 84,581	$ 6.77	$ 9.52	$ 13,273	$ 7.04	$ 9,824	$ 88,030	2.19%	$ 157	$ 88,030	$ 9,824
Jan-14	12,500	145	1,395	11,250	$ 88,030	$ 7.04	$11.89	$ 1,724	$ 7.10	$ 9,902	$ 79,852	2.19%	$ 153	$ 79,852	$ 9,902
Feb-14	11,250	1,260	1,260	11,250	$ 79,852	$ 7.10	$10.97	$ 13,816	$ 7.49	$ 9,434	$ 84,234	2.19%	$ 149	$ 84,234	$ 9,434
Mar-14	11,250	1,395	1,395	11,250	$ 84,234	$ 7.49	$ 6.92	$ 9,649	$ 7.42	$ 10,357	$ 83,526	2.19%	$ 153	$ 83,526	$ 10,357
Apr-14	11,250	4,315	3,065	12,500	$ 83,526	$ 7.42	$ 5.59	$ 24,138	$ 6.92	$ 21,201	$ 86,463	2.19%	$ 155	$ 86,463	$ 21,201
May-14	12,500	1,395	1,395	12,500	$ 86,463	$ 6.92	$ 5.61	$ 7,829	$ 6.79	$ 9,466	$ 84,825	2.19%	$ 156	$ 84,825	$ 9,466
Jun-14	12,500	1,350	1,350	12,500	$ 84,825	$ 6.79	$ 5.64	$ 7,614	$ 6.67	$ 9,010	$ 83,429	2.19%	$ 153	$ 83,429	$ 9,010
Jul-14	12,500	1,395	1,395	12,500	$ 83,429	$ 6.67	$ 5.67	$ 7,912	$ 6.57	$ 9,170	$ 82,171	2.19%	$ 151	$ 82,171	$ 9,170
Aug-14	12,500	145	1,395	11,250	$ 82,171	$ 6.57	$ 5.69	$ 825	$ 6.56	$ 9,156	$ 73,840	2.19%	$ 142	$ 73,840	$ 9,156
Sep-14	11,250	2,600	1,350	12,500	$ 73,840	$ 6.56	$ 5.69	$ 14,791	$ 6.40	$ 8,639	$ 79,992	2.19%	$ 140	$ 79,992	$ 8,639
Oct-14	12,500	1,395	1,395	12,500	$ 79,992	$ 6.40	$ 5.71	$ 7,970	$ 6.33	$ 8,831	$ 79,131	2.19%	$ 145	$ 79,131	$ 8,831

Schedule 15

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
May 2012 - April 2013

	AMOUNT	
Winter Period Beg. Balance	($3,105,737)	SCHEDULE 2
Less: Reported Collections	($21,693,173)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$22,696,809	SCHEDULE 4
Add: Interest	($26,148)	SCHEDULE 2
Winter Period Ending Balance	($2,128,249)	

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED WINTER PERIOD ACCOUNTS
May 2012 - April 2013
Acct 191.20

	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
WINTER PERIOD													
Winter Period Account Beginning Balance	$ (3,105,737)	$ (2,458,464)	$ (1,986,837)	$ (1,403,522)	$ (872,999)	$ (321,386)	$ 228,731	$ 1,375,878	$ 1,936,104	$ 355,596	$ (2,031,626)	$ (1,872,114)	$ (3,105,737)
Plus: Cost of Firm Gas (Schedule 4)	$ 498,334	$ 478,439	$ 587,874	$ 533,671	$ 552,336	$ 550,534	$ 3,308,051	$ 4,568,285	$ 3,625,876	$ 2,627,782	$ 3,979,567	$ 1,386,061	$ 22,696,809
Less: Reported Collections (Schedule 3)	$ 156,464	$ (800)	$ 27	$ (70)	$ 892	$ (291)	$ (2,163,075)	$ (4,012,537)	$ (5,209,483)	$ (5,012,738)	$ (3,814,776)	$ (1,636,786)	$ (21,693,173)
Winter Period Account Ending Balance	$ (2,450,940)	$ (1,980,826)	$ (1,398,937)	$ (869,920)	$ (319,771)	$ 228,856	$ 1,373,708	$ 1,931,626	$ 352,497	$ (2,029,359)	$ (1,866,835)	$ (2,122,839)	$ (2,102,101)
Month's Average Balance	$ (2,778,339)	$ (2,219,645)	$ (1,692,887)	$ (1,136,721)	$ (596,385)	$ (46,265)	$ 801,219	$ 1,653,752	$ 1,144,301	$ (836,881)	$ (1,949,231)	$ (1,997,477)	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (7,525)	$ (6,012)	$ (4,585)	$ (3,079)	$ (1,615)	$ (125)	$ 2,170	$ 4,479	$ 3,099	$ (2,267)	$ (5,279)	$ (5,410)	$ (26,148)
Winter Period Account Ending Balance w/int	**$ (2,458,464)**	**$ (1,986,837)**	**$ (1,403,522)**	**$ (872,999)**	**$ (321,386)**	**$ 228,731**	**$ 1,375,878**	**$ 1,936,104**	**$ 355,596**	**$ (2,031,626)**	**$ (1,872,114)**	**$ (2,128,249)**	**$ (2,128,249)**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2012 - April 2013

FORM III
Schedule 3

	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
Accrued Revenue	$ (1,451,736)	$ -	$ -	$ -	$ -	$ -	$1,352,820	$ 586,148	$ 705,874	$ (361,369)	$ (422,187)	$ (905,295)	$ (495,744)
Billed Revenue	$ 1,295,272	$ 800	$ (27)	$ 70	$ (892)	$ 291	$ 810,254	$ 3,426,388	$ 4,503,609	$ 5,374,107	$ 4,236,963	$ 2,542,080	$ 22,188,917
Calendarized Revenue	**$ (156,464)**	**$ 800**	**$ (27)**	**$ 70**	**$ (892)**	**$ 291**	**$ 2,163,075**	**$ 4,012,537**	**$ 5,209,483**	**$ 5,012,738**	**$ 3,814,776**	**$ 1,636,786**	**$ 21,693,173**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2012 - April 2013

Commodity Costs:	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**Total Winter**
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,231	$ -	$ -	**$ 70,231**
Chesapeake	$ 208,794	$ 188,603	$ -	$ 11,012	$ -	$ -	$ -	$ -	$ 66,603	$ 2,761	$ -	$ 91,688	**$ 569,460**
DTE	$ 75,486	$ -	$ -	$ -	$ -	$ -	$ -	$ 77,888	$ 143,623	$ 463,066	$ 92,183	$ 97,971	**$ 950,216**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Emera Energy	$ -	$ -	$ -	$ (753)	$ -	$ -	$ -	$ 539,548	$ 591,997	$ 554,769	$ 489,696	$ 606,668	**$ 2,781,926**
Freepoint	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 361,617	$ 449,685	$ 404,358	$ 352,614	$ 435,957	**$ 2,004,232**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Macquarie Cook	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 220,173	$ 265,611	$ 238,100	$ 207,786	$ 268,101	**$ 1,199,771**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 121,319	$ -	$ 7,431	$ -	$ -	**$ 128,750**
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 397,330	$ 429,186	$ 399,930	$ 354,450	$ 446,208	**$ 2,027,105**
United Energy Trading	$ 192,105	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,273	$ 132,511	$ 309,293	$ 149,564	$ 182,022	**$ 1,088,768**
Allocation Adjustment Reversal	$ -	$ -	$ -	$ -	$ -	$ (4,513)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (4,513)**
Subtotal - Commodiity Supply	$ 476,385	$ 188,603	$ -	$ 10,259	$ -	$ (4,513)	$ -	$ 1,841,148	$ 2,079,216	$ 2,449,939	$ 1,646,293	$ 2,128,615	**$ 10,815,946**
Transportation Costs:													
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 431	$ 778	$ 874	$ 767	$ 632	$ 147	**$ 3,629**
Portland	$ 52	$ 26	$ -	$ 63	$ 58	$ -	$ -	$ 23	$ 15,682	$ 15,682	$ 54,104	$ 26	**$ 85,715**
Tennessee	$ 11,190	$ 7,356	$ -	$ -	$ -	$ -	$ -	$ 11,609	$ 12,163	$ 13,216	$ 12,900	$ 15,511	**$ 83,946**
Subtotal - Commodity Transportation	$ 11,241	$ 7,382	$ -	$ 63	$ 58	$ -	$ 431	$ 12,410	$ 28,719	$ 29,665	$ 67,637	$ 15,683	**$ 173,290**
Commodity Cost Estimates	$ 188,603	$ -	$ -	$ -	$ -	$ -	$ 1,852,530	$ 2,088,827	$ 2,488,224	$ 1,703,238	$ 2,145,187	$ 701,842	**$ 11,168,451**
Commodity Cost Reversals	$ (677,517)	$ (188,603)	$ -	$ -	$ -	$ -	$ -	$ (1,852,530)	$ (2,088,827)	$ (2,488,224)	$ (1,703,238)	$ (2,145,187)	**$ (11,144,126)**
Subtotal - Supply	$ (1,288)	$ 7,382	$ -	$ 10,322	$ 58	$ (4,513)	$ 1,852,961	$ 2,089,856	$ 2,507,332	$ 1,694,618	$ 2,155,879	$ 700,954	**$ 11,013,561**
Withdrawal - Underground Storage	$ -	$ 466	$ -	$ -	$ -	$ -	$ 382,761	$ 991,958	$ 1,346,992	$ 1,376,321	$ 931,967	$ 58,571	**$ 5,089,037**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,841	$ 5,113	$ 49,472	$ 43,809	$ 13,519	$ 12,428	**$ 128,183**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,056	$ (63,384)	$ (233,484)	$ (266,002)	$ (48,225)	$ 38,135	**$ (565,904)**
Off System Sales	$ (115,232)	$ -	$ -	$ -	$ -	$ -	$ -	$ (469,794)	$ (19,193)	$ (1,092,955)	$ (1,802,092)	$ (737,822)	**$ (4,237,089)**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,354	$ (587)	$ (25,821)	$ (25,928)	$ (3,970)	$ 111	**$ (47,842)**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (191,283)	$ (354,796)	$ (514,113)	$ (532,336)	$ (274,993)	**$ (1,867,521)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Transportation Charges	$ 27,665	$ 21,233	$ (778)	$ (75)	$ -	$ -	$ -	$ -	$ (2)	$ (164,605)	$ 40,222	$ -	**$ (76,339)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,296	$ 121,399	$ 164,393	$ 142,647	$ 129,855	$ 28,072	**$ 587,661**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Inventory Finance Charage	$ 152	$ 148	$ 214	$ 345	$ 431	$ 512	$ 527	$ 560	$ 463	$ 251	$ 139	$ 82	**$ 3,824**
Prior Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Subtotal - Other Commodity	$ (87,415)	$ 21,848	$ (564)	$ 269	$ 431	$ 512	$ 403,835	$ 393,982	$ 928,023	$ (500,574)	$ (1,270,922)	$ (875,415)	**$ (985,989)**
Off System Sales Estimates	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (661,077)**	**$ (373,989)**	**$ (1,974,267)**	**$ (2,341,488)**	**$ (1,012,815)**	**$ -**	**$ (6,363,636)**
Off System Sales Reversals	**$ 115,281**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 661,077**	**$ 373,989**	**$ 1,974,267**	**$ 2,341,488**	**$ 1,012,815**	**$ 6,478,917**
Subtotal Estimates/Reversals	**$ 115,281**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (661,077)**	**$ 287,088**	**$ (1,600,278)**	**$ (367,221)**	**$ 1,328,673**	**$ 1,012,815**	**$ 115,281**
Total Commodity Costs	$ 26,578	$ 29,230	$ (564)	$ 10,591	$ 489	$ (4,001)	$ 1,595,719	$ 2,770,926	$ 1,835,077	$ 826,824	$ 2,213,630	$ 838,354	**$ 10,142,853**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2012 - April 2013

Demand Costs	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total Winter
Pipeline Reservation													
Alberta Northeast	$ -	$ -	$ -	$ 10,109	$ 11,068	$ 10,325	$ 11,914	$ 10,587	$ 6,829	$ 6,438	$ 5,773	$ 6,845	**$ 79,889**
Algonquin	$ 15,741	$ 15,741	$ 15,741	$ 15,741	$ 15,741	$ 15,741	$ 15,741	$ 15,761	$ 15,761	$ 15,757	$ 15,689	$ 15,743	**$ 188,897**
DTE Energy	$ 456,368	$ 457,537	$ 459,436	$ 473,769	$ 480,778	$ 472,516	$ 473,094	$ 462,320	$ 458,454	$ 448,647	$ 449,844	$ 447,852	**$ 5,540,616**
Freepoint	$ 32,808	$ 32,753	$ 33,505	$ 34,009	$ 34,406	$ 33,781	$ 33,860	$ 33,085	$ 32,809	$ 32,104	$ 32,189	$ 32,053	**$ 397,360**
Granite State	$ 146,878	$ 146,878	$ 146,878	$ 155,942	$ 155,942	$ 155,942	$ 152,716	$ 152,716	$ 152,716	$ 152,716	$ 152,716	$ 152,716	**$ 1,824,757**
Iroquois	$ 20,533	$ 20,533	$ 20,533	$ 20,538	$ 20,533	$ 20,533	$ 20,533	$ 20,108	$ 20,108	$ 20,108	$ 20,108	$ 20,108	**$ 244,275**
Portland	$ 20,975	$ 20,975	$ 20,975	$ 20,975	$ 20,975	$ 20,975	$ 20,975	$ 1,191,398	$ 1,191,398	$ 1,191,398	$ 1,191,398	$ 1,191,398	**$ 6,103,816**
Tennessee	$ 183,018	$ 183,134	$ 183,018	$ 183,018	$ 183,018	$ 183,018	$ 183,018	$ 179,232	$ 179,232	$ 179,232	$ 179,232	$ 179,232	**$ 2,177,401**
Texas Eastern	$ 3,231	$ 3,317	$ 3,231	$ 3,069	$ 3,191	$ 3,191	$ 3,191	$ 2,550	$ 2,551	$ 2,551	$ 2,479	$ 2,479	**$ 35,029**
Union	$ 7,128	$ 6,738	$ 6,784	$ 6,875	$ 7,019	$ 7,121	$ 7,061	$ 6,847	$ 6,895	$ 6,883	$ 6,763	$ 6,667	**$ 82,782**
Vector	$ 85,629	$ 85,612	$ 85,624	$ 85,662	$ 85,681	$ 85,674	$ 85,642	$ 120,065	$ 120,064	$ 120,043	$ 120,014	$ 120,029	**$ 1,199,739**
Total Pipeline Reservation	$ 972,308	$ 973,218	$ 975,725	$ 1,009,707	$ 1,018,351	$ 1,008,816	$ 1,007,744	$ 2,194,670	$ 2,186,819	$ 2,175,876	$ 2,176,206	$ 2,175,123	**$ 17,874,562**
Product Demand													
Alberta Northeast	$ 9,448	$ -	$ 18,587	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 28,035**
BG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,640	$ 4,640	$ 4,640	$ 4,640	$ 4,640	
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,868	$ 54,868	$ 54,868	$ 54,868	$ 54,868	**$ 274,340**
DTE Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 24,747	$ 24,747	$ 24,747	$ -	**$ 74,240**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,104	$ 5,104	$ 5,104	$ 5,104	$ 5,104	**$ 25,520**
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,136	$ -	$ -	$ -	$ -	**$ 11,136**
Total Product Demand	$ 9,448	$ -	$ 18,587	$ -	$ -	$ -	$ -	$ 75,748	$ 89,359	$ 89,359	$ 89,359	$ 64,612	**$ 436,471**
Storage Pipeline Transportation and Demand Reservation													
Tennessee	$ 5,689	$ 5,689	$ 5,689	$ 5,689	$ 5,689	$ 5,689	$ 5,689	$ 5,571	$ 5,571	$ 5,571	$ 5,571	$ 5,571	**$ 67,674**
Texas Eastern	$ 82	$ 82	$ 81	$ 243	$ 81	$ 81	$ 81	$ 81	$ 81	$ 94	$ 80	$ 80	**$ 1,147**
Wash 10	$ 114,107	$ 114,107	$ 114,107	$ 114,107	$ 114,107	$ 114,107	$ 114,107	$ 111,747	$ 111,747	$ 111,747	$ 111,747	$ 111,747	**$ 1,357,481**
Company Managed	$ (200,508)	$ (197,152)	$ (210,625)	$ (79,277)	$ (170,380)	$ (167,474)	$ (212,616)	$ (486,095)	$ (493,744)	$ (495,720)	$ (483,550)	$ (476,036)	**$ (3,673,178)**
Total Storage and Demand Reservation	$ (80,631)	$ (77,275)	$ (90,748)	$ 40,761	$ (50,504)	$ (47,598)	$ (92,739)	$ (368,697)	$ (376,346)	$ (378,308)	$ (366,153)	$ (358,639)	**$ (2,246,875)**
Demand Cost Estimates	$ 756,808	$ 743,335	$ 874,683	$ 797,057	$ 805,687	$ 831,410	$ 1,737,952	$ 1,743,545	$ 1,744,470	$ 1,767,369	$ 1,742,437	$ 781,605	**$ 14,326,358**
Demand Cost Reversals	$ (764,457)	$ (756,808)	$ (743,335)	$ (874,683)	$ (797,057)	$ (805,687)	$ (831,410)	$ (1,737,952)	$ (1,743,545)	$ (1,744,470)	$ (1,767,369)	$ (1,742,437)	**$ (14,309,210)**
Subtotal	$ (7,649)	$ (13,473)	$ 131,348	$ (77,626)	$ 8,630	$ 25,723	$ 906,542	$ 5,593	$ 925	$ 22,899	$ (24,932)	$ (960,832)	**$ 17,148**
Total Direct Demand Costs	$ 893,476	$ 882,469	$ 1,034,911	$ 972,842	$ 976,478	$ 986,941	$ 1,821,547	$ 1,907,314	$ 1,900,757	$ 1,909,826	$ 1,874,480	$ 920,265	**$ 16,081,306**
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,320	$ 25,320	$ 25,320	$ 25,320	$ 25,320	$ 25,320	**$ 151,922**
Capacity Release	$ (241,316)	$ (257,997)	$ (274,827)	$ (273,840)	$ (267,533)	$ (258,489)	$ (242,115)	$ (226,730)	$ (226,817)	$ (226,698)	$ (225,860)	$ (225,030)	**$ (2,947,252)**
Capacity Mitigation	$ (15,293)	$ (15,400)	$ (15,398)	$ (16,184)	$ (16,378)	$ (16,384)	$ (15,645)	$ (12,723)	$ (13,379)	$ (13,379)	$ (13,379)	$ (13,379)	**$ (176,921)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 53,624	$ 53,624	$ 53,624	$ 53,624	$ 53,624	$ 53,624	**$ 321,744**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	**$ 307,762**
Total Indirect Demand Costs	$ (256,609)	$ (273,397)	$ (290,225)	$ (290,024)	$ (283,911)	$ (274,872)	$ (127,523)	$ (109,215)	$ (109,958)	$ (109,839)	$ (109,001)	$ (108,171)	**$ (2,342,744)**
Demand Cost Estimates - Capacity Release	$ (264,348)	$ (266,893)	$ (265,823)	$ (268,243)	$ (251,644)	$ (251,859)	$ (233,552)	$ (234,293)	$ (234,293)	$ (233,321)	$ (232,863)	$ (497,250)	**$ (3,234,382)**
Demand Cost Reversals - Capacity Release	$ 256,556	$ 264,348	$ 266,893	$ 265,823	$ 268,243	$ 251,644	$ 251,859	$ 233,552	$ 234,293	$ 234,293	$ 233,321	$ 232,863	**$ 2,993,688**
Subtotal	$ (7,792)	$ (2,545)	$ 1,070	$ (2,420)	$ 16,599	$ (215)	$ 18,307	$ (741)	$ -	$ 972	$ 458	$ (264,387)	**$ (240,694)**
Total Demand Costs	**$ 629,075**	**$ 606,528**	**$ 745,756**	**$ 680,398**	**$ 709,166**	**$ 711,853**	**$ 1,712,332**	**$ 1,797,358**	**$ 1,790,799**	**$ 1,800,958**	**$ 1,765,937**	**$ 547,707**	$ 13,497,867
Demand Costs Transferred to Summer	$ (157,319)	$ (157,319)	$ (157,319)	$ (157,319)	$ (157,319)	$ (157,319)	$ -	$ -	$ -	$ -	$ -	$ -	$ (943,912)
Net Demand Costs For Winter Period	**$ 471,756**	**$ 449,209**	**$ 588,437**	**$ 523,080**	**$ 551,847**	**$ 554,535**	**$ 1,712,332**	**$ 1,797,358**	**$ 1,790,799**	**$ 1,800,958**	**$ 1,765,937**	**$ 547,707**	$ 12,553,955
Total Gas Costs	**$ 498,334**	**$ 478,439**	**$ 587,874**	**$ 533,671**	**$ 552,336**	**$ 550,534**	**$ 3,308,051**	**$ 4,568,285**	**$ 3,625,876**	**$ 2,627,782**	**$ 3,979,567**	**$ 1,386,061**	$ 22,696,809

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
May 2012 - April 2013

Total

[redacted]

Commodity Volumes:

BP
Chesapeake
DTE
Distrigas
Emera Energy
Freepoint
Granite
Macquire Cook
JP Morgan
Shell
United
Virginia Power
Subtotal - Commodity Supply

Transportation Volumes
Granite
Portland
Tennessee
Subtotal - Commodity Transportation

Commodity Volume Estimates
Commodity Volume Reversals

Subtotal - Supply

Withdrawal - Underground Storage
Withdrawal - LNG Vaporization
ATV Reconciliation
Off System Sales
Net OBA Adjustment
Company Managed
LNG Boiloff
Transportation Charges
Hedging Costs
Propane
Inventory Finance Charge
Prior Period Adjustment

Subtotal - Other Commodity

Off System & Company Managed Estimates
Off System & Company Managed Reversals

Total Commodity Volumes

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
May 2012 - April 2013

REDACTED

Commodity Costs:	[redacted]
BP	[redacted]
Chesapeake	[redacted]
DTE	[redacted]
Distrigas	[redacted]
Emera Energy	[redacted]
Freepoint	[redacted]
Granite	[redacted]
Macquarie Cook	[redacted]
JP Morgan	[redacted]
Shell	[redacted]
United Energy Trading	[redacted]
Virginia Power	[redacted]
Subtotal - Commodity Supply	[redacted]
Transportation Costs:	[redacted]
Granite	[redacted]
Portland	[redacted]
Tennessee	[redacted]
Subtotal - Commodity Transportation	[redacted]
Commodity Cost Estimates	[redacted]
Commodity Cost Reversals	[redacted]
Subtotal - Supply	[redacted]
Withdrawal - Underground Storage	[redacted]
Withdrawal - LNG Vaporization	[redacted]
ATV Reconciliation Charges	[redacted]
Off System Sales	[redacted]
Net OBA Adjustment	[redacted]
Company Managed	[redacted]
LNG Boiloff	[redacted]
Transportation Charges	[redacted]
Hedging Costs	[redacted]
Propane	[redacted]
Prior Period Adjustments	[redacted]
Subtotal - Other Commodity	[redacted]
Off System Sales Estimates	[redacted]
Off System Sales Reversals	[redacted]
Total Commodity Costs	[redacted]

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
May 2012 - April 2013

Commodity Costs:	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**Total Winter**
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 82,579	$ -	$ -	$ 82,579
Chesapeake	$ 198,133	$ 173,052	$ -	$ 9,328	$ -	$ -	$ -	$ -	$ 76,660	$ 3,246	$ -	$ 89,442	$ 549,860
DTE	$ 71,631	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,628	$ 165,310	$ 544,475	$ 107,563	$ 95,571	$ 1,075,178
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Emera Energy	$ -	$ -	$ -	$ (638)	$ -	$ -	$ -	$ 627,800	$ 681,388	$ 652,301	$ 571,401	$ 591,807	$ 3,124,059
Freepoint	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 420,765	$ 517,588	$ 475,447	$ 411,447	$ 425,278	$ 2,250,524
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Macquarie Cook	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 256,185	$ 305,719	$ 279,959	$ 242,454	$ 261,534	$ 1,345,851
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 141,163	$ -	$ 8,737	$ -	$ -	$ 149,900
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 462,320	$ 493,994	$ 470,240	$ 413,590	$ 435,277	$ 2,275,420
United Energy Trading	$ 182,295	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,436	$ 152,520	$ 363,668	$ 174,519	$ 177,563	$ 1,194,002
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Allocation Adjustment Reversal	$ -	$ -	$ -	$ -	$ -	$ 4,513	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,513
Subtotal - Commodity Supply	$ 452,059	$ 173,052	$ -	$ 8,690	$ -	$ 4,513	$ -	$ 2,142,297	$ 2,393,179	$ 2,880,651	$ 1,920,973	$ 2,076,472	$ 12,051,885
Transportation Costs:													
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 502	$ 896	$ 1,027	$ 895	$ 617	$ 137	$ 4,074
Portland	$ 49	$ 25	$ -	$ 53	$ 48	$ -	$ -	$ 26	$ 18,050	$ 18,050	$ 63,768	$ 25	$ 100,094
Tennessee	$ 10,618	$ 7,165	$ -	$ -	$ -	$ -	$ -	$ 13,508	$ 14,000	$ 15,540	$ 15,053	$ 15,131	$ 91,015
Subtotal - Commodity Transportation	$ 10,667	$ 7,190	$ -	$ 53	$ 48	$ -	$ 502	$ 14,431	$ 33,077	$ 34,485	$ 79,437	$ 15,293	$ 195,183
Commodity Cost Estimates	$ 173,051	$ -	$ -	$ -	$ -	$ -	$ 2,155,540	$ 2,404,240	$ 2,925,665	$ 1,988,055	$ 2,092,637	$ 657,001	$ 12,396,189
Commodity Cost Reversals	$ (637,000)	$ (173,051)	$ -	$ -	$ -	$ -	$ -	$ (2,155,540)	$ (2,404,240)	$ (2,925,665)	$ (1,988,055)	$ (2,092,637)	$ (12,376,188)
Subtotal - Supply	$ (1,222)	$ 7,190	$ -	$ 8,744	$ 48	$ 4,513	$ 2,156,042	$ 2,405,427	$ 2,947,680	$ 1,977,526	$ 2,104,992	$ 656,130	$ 12,267,069
Withdrawal - Underground Storage	$ -	$ 454	$ -	$ -	$ -	$ -	$ 445,367	$ 1,141,744	$ 1,583,798	$ 1,605,960	$ 909,206	$ 54,836	$ 5,741,365
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,469	$ 5,886	$ 58,170	$ 51,118	$ 13,188	$ 11,634	$ 144,465
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,210	$ (72,955)	$ (274,532)	$ (310,383)	$ (47,044)	$ 35,699	$ (661,005)
Off System Sales	$ (109,348)	$ -	$ -	$ -	$ -	$ -	$ -	$ (546,636)	$ (22,092)	$ (1,285,102)	$ (2,102,766)	$ (719,748)	$ (4,785,692)
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,721	$ (676)	$ (30,361)	$ (30,254)	$ (3,872)	$ 104	$ (55,339)
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (327,250)	$ (730,251)	$ (1,248,686)	$ (1,528,326)	$ (421,160)	$ (4,255,674)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transportation Charges	$ 26,253	$ 20,680	$ (722)	$ (64)	$ -	$ -	$ -	$ -	$ (2)	$ (193,543)	$ 46,933	$ -	$ (100,465)
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,508	$ 139,731	$ 193,294	$ 166,447	$ 126,674	$ 26,278	$ 653,931
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 479	$ 447	$ 858	$ 1,060	$ 874	$ 693	$ 4,411
Inventory Finance Charage	$ 148	$ 138	$ 181	$ 288	$ 362	$ 511	$ 614	$ 644	$ 544	$ 293	$ 135	$ 77	$ 3,934
Prior Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Other Commodity	$ (82,947)	$ 21,272	$ (540)	$ 224	$ 362	$ 511	$ 470,367	$ 340,934	$ 779,425	$ (1,243,090)	$ (2,584,999)	$ (1,011,587)	$ (3,310,069)
Off System Sales Estimates	-	-	-	-	-	-	(873,886)	(752,343)	(2,965,542)	(3,639,330)	(1,140,908)	-	(9,372,009)
Off System Sales Reversals	109,395	-	-	-	-	-	-	873,886	752,343	2,965,542	3,639,330	1,140,908	9,481,404
Subtotal Estimates/Reversals	109,395	-	-	-	-	-	(873,886)	121,543	(2,213,199)	(673,788)	2,498,422	1,140,908	109,395
Total Commodity Costs	25,225	28,462	(540)	8,967	410	5,024	1,752,523	2,867,905	1,513,906	60,648	2,018,415	785,451	- 9,066,396

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
May 2012 - April 2013

Demand Costs	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**Total Winter**
Pipeline Reservation													
Alberta Northeast	$ -	$ -	$ -	$ 11,227	$ 12,292	$ 11,467	$ 13,232	$ 12,230	$ 7,889	$ 7,437	$ 6,669	$ 7,908	$ 90,350
Algonquin	$ 17,482	$ 17,482	$ 17,482	$ 17,482	$ 17,482	$ 17,482	$ 17,482	$ 18,207	$ 18,207	$ 18,202	$ 18,124	$ 18,186	$ 213,297
DTE Energy	$ 506,840	$ 508,138	$ 510,248	$ 526,165	$ 533,950	$ 524,774	$ 525,415	$ 534,059	$ 529,594	$ 518,265	$ 519,648	$ 517,347	$ 6,254,444
Freepoint	$ 36,436	$ 36,375	$ 37,210	$ 37,770	$ 38,211	$ 37,517	$ 37,604	$ 38,219	$ 37,900	$ 37,085	$ 37,184	$ 37,027	$ 448,538
Granite State	$ 163,122	$ 163,122	$ 163,122	$ 173,188	$ 173,188	$ 173,188	$ 176,414	$ 176,414	$ 176,414	$ 176,414	$ 176,414	$ 176,414	$ 2,067,413
Iroquois	$ 22,804	$ 22,804	$ 22,804	$ 22,810	$ 22,804	$ 22,804	$ 22,804	$ 23,228	$ 23,228	$ 23,228	$ 23,228	$ 23,228	$ 275,773
Portland	$ 23,295	$ 23,295	$ 23,295	$ 23,295	$ 23,295	$ 23,295	$ 23,295	$ 1,376,270	$ 1,376,270	$ 1,376,270	$ 1,376,270	$ 1,376,270	$ 7,044,415
Tennessee	$ 203,259	$ 203,388	$ 203,259	$ 203,259	$ 203,259	$ 203,259	$ 203,259	$ 207,044	$ 207,044	$ 207,044	$ 207,044	$ 207,044	$ 2,458,160
Texas Eastern	$ 3,588	$ 3,684	$ 3,588	$ 3,408	$ 3,544	$ 3,544	$ 3,544	$ 2,946	$ 2,947	$ 2,947	$ 2,863	$ 2,863	$ 39,465
Union	$ 7,917	$ 7,483	$ 7,535	$ 7,636	$ 7,795	$ 7,909	$ 7,842	$ 7,909	$ 7,965	$ 7,951	$ 7,812	$ 7,701	$ 93,455
Vector	$ 95,099	$ 95,080	$ 95,094	$ 95,136	$ 95,157	$ 95,149	$ 95,113	$ 138,696	$ 138,695	$ 138,670	$ 138,637	$ 138,655	$ 1,359,181
Total Pipeline Reservation	$1,079,841	$1,080,851	$1,083,635	$1,121,375	$1,130,976	$1,120,386	$1,126,004	$2,535,222	$2,526,153	$2,513,512	$2,513,893	$2,512,643	$20,344,490
Product Demand													
Alberta Northeast	$ 10,493	$ -	$ 20,642	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,135
BG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,360	$ 5,360	$ 5,360	$ 5,360	$ 5,360	$ 26,800
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,382	$ 63,382	$ 63,382	$ 63,382	$ 63,382	$ 316,910
DTE Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,587	$ 28,587	$ 28,587	$ -	$ 85,760
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,896	$ 5,896	$ 5,896	$ 5,896	$ 5,896	$ 29,480
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,864	$ -	$ -	$ -	$ -	$ 12,864
Total Product Demand	$10,493	$0	$20,642	$0	$0	$0	$0	$87,502	$103,225	$103,225	$103,225	$74,638	$502,949
Storage Pipeline Transportation and Demand Reservation													
Tennessee	$ 6,318	$ 6,318	$ 6,318	$ 6,318	$ 6,318	$ 6,318	$ 6,318	$ 6,435	$ 6,435	$ 6,435	$ 6,435	$ 6,435	$ 76,400
Texas Eastern	$ 91	$ 91	$ 90	$ 270	$ 90	$ 90	$ 90	$ 94	$ 94	$ 81	$ 92	$ 93	$ 1,265
Wash 10	$ 126,727	$ 126,727	$ 126,727	$ 126,727	$ 126,727	$ 126,727	$ 126,727	$ 129,087	$ 129,087	$ 129,087	$ 129,087	$ 129,087	$ 1,532,519
Company Managed	$ -	$ -	$ -	$ 0	$ -	$ -	$ (13,225)	$ (1,194,633)	$ (1,204,507)	$ (1,169,005)	$ (1,167,844)	$ (1,164,504)	$ (5,913,717)
Total Storage and Demand Reservation	$ 133,135	$ 133,135	$ 133,135	$ 133,314	$ 133,134	$ 133,134	$ 119,910	$ (1,059,017)	$ (1,068,891)	$ (1,033,402)	$ (1,032,230)	$ (1,028,889)	$ (4,303,533)
Demand Cost Estimates	$ 1,059,464	$ 1,059,464	$ 1,059,464	$ 1,074,432	$ 1,080,788	$ 1,070,187	$ 1,374,525	$ 1,379,948	$ 1,418,801	$ 1,432,356	$ 1,398,215	$ 1,077,283	$ 14,484,927
Demand Cost Reversals	$ (1,063,179)	$ (1,059,464)	$ (1,059,464)	$ (1,059,464)	$ (1,074,432)	$ (1,080,788)	$ (1,070,187)	$ (1,374,525)	$ (1,379,948)	$ (1,418,801)	$ (1,432,356)	$ (1,398,215)	$ (14,470,823)
Subtotal Estimates/Reversals	$ (3,715)	$ -	$ -	$ 14,968	$ 6,356	$ (10,601)	$ 304,338	$ 5,423	$ 38,853	$ 13,555	$ (34,141)	$ (320,932)	$ 14,104
Totall Direct Demand Costs	$ 1,219,753	$ 1,213,986	$ 1,237,412	$ 1,269,658	$ 1,270,466	$ 1,242,919	$ 1,550,251	$ 1,569,130	$ 1,599,339	$ 1,596,890	$ 1,550,747	$ 1,237,459	$ 16,558,010
Amortization of PNGTS Rate Case Costs	$ 610	$ 423	$ 364	$ 346	$ 372	$ 770	$ 1,773	$ 26,873	$ 66,928	$ 50,609	$ 28,244	$ 11,265	$ 188,577
Capacity Release	$ (217,004)	$ (217,129)	$ (217,903)	$ (215,826)	$ (225,753)	$ (234,291)	$ (217,010)	$ (220,392)	$ (224,188)	$ (224,933)	$ (224,365)	$ (225,105)	$ (2,663,899)
Capacity Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,160	$ 75,160	$ 75,160	$ 75,160	$ 75,160	$ 75,160	$ 450,958
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,790	$ 52,790	$ 52,790	$ 52,790	$ 52,790	$ 52,790	$ 316,739
Total Indirect Demand Costs	$ (216,394)	$ (216,705)	$ (217,539)	$ (215,480)	$ (225,381)	$ (233,522)	$ (87,288)	$ (65,569)	$ (29,310)	$ (46,374)	$ (68,171)	$ (85,891)	$ (1,707,626)
Demand Cost Estimates - Capacity Release	$ (225,586)	$ (225,349)	$ (225,586)	$ (225,612)	$ (225,338)	$ (216,741)	$ (219,941)	$ (220,037)	$ (220,037)	$ (219,747)	$ (219,954)	$ (530,136)	$ (2,974,064)
Demand Cost Reversals - Capacity Release	$ 216,514	$ 225,586	$ 225,349	$ 225,586	$ 225,612	$ 225,338	$ 216,741	$ 219,941	$ 220,037	$ 220,037	$ 219,747	$ 219,954	$ 2,660,442
Subtotal	$ (9,072)	$ 237	$ (237)	$ (26)	$ 274	$ 8,597	$ (3,200)	$ (96)	$ -	$ 290	$ (207)	$ (310,182)	$ (313,622)
Total Demand Costs	$ 994,287	$ 997,517	$ 1,019,636	$ 1,054,152	$ 1,045,359	$ 1,017,994	$ 1,459,764	$ 1,503,465	$ 1,570,029	$ 1,550,806	$ 1,482,369	$ 841,386	$ 14,536,763
Demand Costs Transferred to Summer	$ (142,053)	$ (142,053)	$ (142,053)	$ (142,053)	$ (142,053)	$ (142,053)	$ -	$ -	$ -	$ -	$ -	$ -	$ (852,315)
Net Demand Costs For Winter Period	**$ 852,234**	**$ 855,465**	**$ 877,584**	**$ 912,099**	**$ 903,306**	**$ 875,942**	**$ 1,459,764**	**$ 1,503,465**	**$ 1,570,029**	**$ 1,550,806**	**$ 1,482,369**	**$ 841,386**	**$ 13,684,448**
Total Gas Costs	**$ 877,459**	**$ 883,927**	**$ 877,044**	**$ 921,066**	**$ 903,716**	**$ 880,965**	**$ 3,212,287**	**$ 4,371,369**	**$ 3,083,935**	**$ 1,611,453**	**$ 3,500,784**	**$ 1,626,837**	**$ 22,750,843**

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
May 2012 - April 2013

REDACTED

[redacted]

[redacted]

Commodity Volumes:

BP
Chesapeake
DTE
Distrigas
Emera Energy
Freepoint
Granite
Macquire Cook
JP Morgan
Shell
United
Virginia Power

Subtotal - Commodity Costs

Transportation Volumes
Granite
Portland
Tennessee
Subtotal- Commodity Transportation

Commodity Volume Estimates
Commodity Volume Reversals

Subtotal - Supply

Withdrawal - Underground Storage
Withdrawal - LNG Vaporization
ATV Reconciliation
Off System Sales
Net OBA Adjustment
Company Managed
LNG Boiloff
Transportation Charges
Hedging Costs
Propane
Inventory Finance Charge
Prior Period Adjustment

Subtotal - Other Commodity

Off System & Company Managed Estimates
Off System & Company Managed Reversals

Total Commodity Volumes

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
May 2012 - April 2013

REDACTED

Commodity Costs:

BP
Chesapeake
DTE
Distrigas
Emera Energy
Freepoint
Granite
Macquarie Cook
JP Morgan
Shell
United Energy Trading
Virginia Power

Subtotal - Commodity Supply

Transportation Costs:
Granite
Portland
Tennessee
Subtotal - Commoditty Transportation

Commodity Cost Estimates
Commodity Cost Reversals

Subtotal - Supply

Withdrawal - Underground Storage
Withdrawal - LNG Vaporization
ATV Reconciliation Charges
Off System Sales
Net OBA Adjustment
Company Managed
LNG Boiloff
Transportation Charges
Hedging Costs
Propane
Inventory Finance Charge
Prior Period Adjustments

Subtotal - Other Commodity

Off System Sales Estimates
Off System Sales Reversals

Total Commodity Costs

[redacted]

NORTHERN UTILITIES, INC. - BOTH DIVISIONs
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2012 - April 2013

Commodity Costs:	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**Total Winter**
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 152,810	$ -	$ -	$ 152,810
Chesapeake	$ 406,927	$ 361,654	$ -	$ 20,340	$ -	$ -	$ -	$ -	$ 143,262	$ 6,007	$ -	$ 181,130	$ 1,119,320
DTE	$ 147,117	$ -	$ -	$ -	$ -	$ -	$ -	$ 168,516	$ 308,934	$ 1,007,540	$ 199,746	$ 193,542	$ 2,025,394
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Emera Energy	$ -	$ -	$ -	$ (1,391)	$ -	$ -	$ -	$ 1,167,348	$ 1,273,385	$ 1,207,070	$ 1,061,097	$ 1,198,476	$ 5,905,985
Freepoint	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 782,383	$ 967,273	$ 879,805	$ 764,061	$ 861,235	$ 4,254,756
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Macquarie Cook	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 476,358	$ 571,330	$ 518,059	$ 450,240	$ 529,635	$ 2,545,622
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 262,482	$ -	$ 16,168	$ -	$ -	$ 278,650
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 859,650	$ 923,180	$ 870,170	$ 768,040	$ 881,485	$ 4,302,525
United Energy Trading	$ 374,400	$ -	$ -	$ -	$ -	$ -	$ -	$ 266,709	$ 285,032	$ 672,961	$ 324,083	$ 359,586	$ 2,282,770
Allocation Adjustment Reversal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Commodity Supply	$ 928,444	$ 361,654	$ -	$ 18,949	$ -	$ -	$ -	$ 3,983,445	$ 4,472,395	$ 5,330,590	$ 3,567,266	$ 4,205,088	$ 22,867,832
Transportation Costs:													
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 933	$ 1,674	$ 1,901	$ 1,662	$ 1,249	$ 284	$ 7,703
Portland	$ 100	$ 51	$ -	$ 117	$ 106	$ -	$ -	$ 49	$ 33,732	$ 33,732	$ 117,872	$ 50	$ 185,809
Tennessee	$ 21,808	$ 14,521	$ -	$ -	$ -	$ -	$ -	$ 25,118	$ 26,163	$ 28,756	$ 27,953	$ 30,643	$ 174,961
Subtotal - Commodity Transporation	$ 21,909	$ 14,572	$ -	$ 117	$ 106	$ -	$ 933	$ 26,841	$ 61,796	$ 64,150	$ 147,074	$ 30,977	$ 368,473
Commodity Cost Estimates	$ 361,654	$ -	$ -	$ -	$ -	$ -	$ 4,008,070	$ 4,493,067	$ 5,413,889	$ 3,691,293	$ 4,237,824	$ 1,358,843	$ 23,564,640
Commodity Cost Reversals	$ (1,314,517)	$ (361,654)	$ -	$ -	$ -	$ -	$ -	$ (4,008,070)	$ (4,493,067)	$ (5,413,889)	$ (3,691,293)	$ (4,237,824)	$ (23,520,314)
Subtotal - Supply	$ (2,511)	$ 14,572	$ -	$ 19,066	$ 106	$ -	$ 4,009,003	$ 4,495,283	$ 5,455,013	$ 3,672,144	$ 4,260,871	$ 1,357,083	$ 23,280,631
Withdrawal - Underground Storage	$ -	$ 921	$ -	$ -	$ -	$ -	$ 828,128	$ 2,133,702	$ 2,930,790	$ 2,982,281	$ 1,841,173	$ 113,407	$ 10,830,402
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,310	$ 10,999	$ 107,642	$ 94,927	$ 26,708	$ 24,063	$ 272,648
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,266	$ (136,339)	$ (508,016)	$ (576,385)	$ (95,269)	$ 73,834	$ (1,226,909)
Off System Sales	$ (224,581)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,016,430)	$ (41,285)	$ (2,378,057)	$ (3,904,859)	$ (1,457,570)	$ (9,022,781)
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,075	$ (1,263)	$ (56,182)	$ (56,182)	$ (7,842)	$ 215	$ (103,181)
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (518,533)	$ (1,085,047)	$ (1,762,799)	$ (2,060,662)	$ (696,153)	$ (6,123,194)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transportation Charges	$ 53,918	$ 41,913	$ (1,499)	$ (139)	$ -	$ -	$ -	$ -	$ (5)	$ (358,148)	$ 87,154	$ -	$ (176,805)
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,804	$ 261,130	$ 357,686	$ 309,093	$ 256,528	$ 54,351	$ 1,241,593
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 479	$ 447	$ 858	$ 1,060	$ 874	$ 693	$ 4,411
Inventory Finance Charage	$ 300	$ 286	$ 395	$ 632	$ 792	$ 1,022	$ 1,141	$ 1,204	$ 1,006	$ 544	$ 274	$ 160	$ 7,758
Prior Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal- Other Commodity	$ (170,362)	$ 43,120	$ (1,104)	$ 493	$ 792	$ 1,022	$ 874,202	$ 734,917	$ 1,707,448	$ (1,743,664)	$ (3,855,921)	$ (1,887,002)	$ (4,296,058)
Off System Sales Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,534,963)	$ (1,126,332)	$ (4,939,809)	$ (5,980,818)	$ (2,153,723)	$ -	$ (15,735,645)
Off System Sales Reversals	$ 224,676	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,534,963	$ 1,126,332	$ 4,939,809	$ 5,980,818	$ 2,153,723	$ 15,960,321
Subtotal Estimates/Reversals	$ 224,676	$ -	$ -	$ -	$ -	$ -	$ (873,886)	$ 782,620	$ (1,839,210)	$ 1,300,479	$ 4,839,910	$ 2,153,723	$ 6,588,312
Total Commodity Costs	$ 51,803	$ 57,692	$ (1,104)	$ 19,559	$ 898	$ 1,022	$ 3,348,243	$ 5,638,831	$ 3,348,983	$ 887,471	$ 4,232,046	$ 1,623,804	$ 19,209,249

NORTHERN UTILITIES, INC. - BOTH DIVISIONs
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD

Demand Costs	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total Winter
Pipeline Reservation													
Alberta Northeast	$ -	$ -	$ -	$ 21,335	$ 23,360	$ 21,791	$ 25,146	$ 22,818	$ 14,718	$ 13,874	$ 12,443	$ 14,753	$ 170,239
Algonquin	$ 33,223	$ 33,223	$ 33,223	$ 33,223	$ 33,223	$ 33,223	$ 33,223	$ 33,969	$ 33,969	$ 33,958	$ 33,813	$ 33,929	$ 402,194
DTE Energy	$ 963,209	$ 965,674	$ 969,684	$ 999,934	$ 1,014,727	$ 997,291	$ 998,509	$ 996,379	$ 988,048	$ 966,912	$ 969,492	$ 965,199	$ 11,795,060
Freepoint	$ 69,243	$ 69,127	$ 70,715	$ 71,778	$ 72,618	$ 71,297	$ 71,464	$ 71,304	$ 70,708	$ 69,189	$ 69,373	$ 69,080	$ 845,898
Granite State	$ 310,000	$ 310,000	$ 310,000	$ 329,130	$ 329,130	$ 329,130	$ 329,130	$ 329,130	$ 329,130	$ 329,130	$ 329,130	$ 329,130	$ 3,892,170
Iroquois	$ 43,336	$ 43,336	$ 43,336	$ 43,348	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 520,048
Portland	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 2,567,668	$ 2,567,668	$ 2,567,668	$ 2,567,668	$ 2,567,668	$ 13,148,231
Tennessee	$ 386,276	$ 386,522	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 4,635,561
Texas Eastern	$ 6,818	$ 7,002	$ 6,818	$ 6,477	$ 6,735	$ 6,735	$ 6,735	$ 5,496	$ 5,498	$ 5,498	$ 5,342	$ 5,342	$ 74,495
Union	$ 15,045	$ 14,221	$ 14,319	$ 14,511	$ 14,814	$ 15,030	$ 14,904	$ 14,756	$ 14,860	$ 14,833	$ 14,575	$ 14,368	$ 176,237
Vector	$ 180,728	$ 180,692	$ 180,718	$ 180,798	$ 180,839	$ 180,822	$ 180,755	$ 258,761	$ 258,759	$ 258,713	$ 258,650	$ 258,684	$ 2,558,920
Total Pipeline Reservation	$ 2,052,149	$ 2,054,069	$ 2,059,360	$ 2,131,082	$ 2,149,328	$ 2,129,202	$ 2,133,748	$ 4,729,893	$ 4,712,971	$ 4,689,388	$ 4,690,099	$ 4,687,766	$ 38,219,052
Product Demand													
Alberta Northeast	$ 19,941	$ -	$ 39,229	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 59,170
BG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 50,000
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 118,250	$ 118,250	$ 118,250	$ 118,250	$ 118,250	$ 591,250
DTE Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53,333	$ 53,333	$ 53,333	$ -	$ 160,000
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,000	$ 11,000	$ 11,000	$ 11,000	$ 11,000	$ 55,000
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,000	$ -	$ -	$ -	$ -	$ 24,000
Total Product Demand	$ 19,941	$ -	$ 39,229	$ -	$ -	$ -	$ -	$ 163,250	$ 192,583	$ 192,583	$ 192,583	$ 139,250	$ 939,420
Storage Pipeline Transportation and Demand Reservation													
Tennessee	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 144,075
Texas Eastern	$ 172	$ 173	$ 172	$ 513	$ 170	$ 171	$ 172	$ 175	$ 175	$ 175	$ 172	$ 173	$ 2,413
Wash 10	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 2,890,000
Company Managed	$ (200,508)	$ (197,152)	$ (210,625)	$ (79,277)	$ (170,380)	$ (167,474)	$ (225,841)	$ (1,680,728)	$ (1,698,251)	$ (1,664,725)	$ (1,651,393)	$ (1,640,540)	$ (9,586,895)
Total Storage and Demand Reservation	$ 52,504	$ 55,860	$ 42,386	$ 174,076	$ 82,630	$ 85,536	$ 27,171	$ (1,427,714)	$ (1,445,236)	$ (1,411,710)	$ (1,398,382)	$ (1,387,528)	$ (6,550,408)
Demand Cost Estimates	$ 1,816,272	$ 1,802,799	$ 1,934,147	$ 1,871,489	$ 1,886,475	$ 1,901,597	$ 3,112,477	$ 3,123,493	$ 3,163,271	$ 3,199,725	$ 3,140,652	$ 1,858,888	$ 28,811,285
Demand Cost Reversals	$ (1,827,636)	$ (1,816,272)	$ (1,802,799)	$ (1,934,147)	$ (1,871,489)	$ (1,886,475)	$ (1,901,597)	$ (3,112,477)	$ (3,123,493)	$ (3,163,271)	$ (3,199,725)	$ (3,140,652)	$ (28,780,033)
Subtotal	$ (11,364)	$ (13,473)	$ 131,348	$ (62,658)	$ 14,986	$ 15,122	$ 1,210,880	$ 11,016	$ 39,778	$ 36,454	$ (59,073)	$ (1,281,764)	$ 31,252
Total Direct Demand Costs	$ 2,113,229	$ 2,096,455	$ 2,272,323	$ 2,242,499	$ 2,246,944	$ 2,229,860	$ 3,371,798	$ 3,476,445	$ 3,500,096	$ 3,506,715	$ 3,425,227	$ 2,157,724	$ 32,639,316
Amortization of PNGTS Rate Case Costs	$ 610	$ 423	$ 364	$ 346	$ 372	$ 770	$ 27,093	$ 52,193	$ 92,248	$ 75,929	$ 53,564	$ 36,585	$ 340,499
Capacity Release	$ (458,320)	$ (475,125)	$ (492,729)	$ (489,666)	$ (493,286)	$ (492,780)	$ (459,125)	$ (447,122)	$ (451,005)	$ (451,631)	$ (450,225)	$ (450,135)	$ (5,611,151)
Capacity Mitigation	$ (15,293)	$ (15,400)	$ (15,398)	$ (16,184)	$ (16,378)	$ (16,384)	$ (15,645)	$ (12,723)	$ (13,379)	$ (13,379)	$ (13,379)	$ (13,379)	$ (176,921)
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 128,784	$ 128,784	$ 128,784	$ 128,784	$ 128,784	$ 128,784	$ 772,702
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 104,084	$ 104,084	$ 104,084	$ 104,084	$ 104,084	$ 104,084	$ 624,501
Total Indirect Demand Costs	$ (473,004)	$ (490,102)	$ (507,764)	$ (505,503)	$ (509,292)	$ (508,394)	$ (214,810)	$ (174,785)	$ (139,269)	$ (156,213)	$ (177,173)	$ (194,061)	$ (4,050,370)
Demand Cost Estimates - Capacity Release	$ (489,934)	$ (492,242)	$ (491,409)	$ (493,855)	$ (476,982)	$ (468,600)	$ (453,493)	$ (454,330)	$ (454,330)	$ (453,068)	$ (452,817)	$ (1,027,386)	$ (6,208,446)
Demand Cost Reversals - Capacity Release	$ 473,070	$ 489,934	$ 492,242	$ 491,409	$ 493,855	$ 476,982	$ 468,600	$ 453,493	$ 454,330	$ 454,330	$ 453,068	$ 452,817	$ 5,654,130
Subtotal	$ (16,864)	$ (2,308)	$ 833	$ (2,446)	$ 16,873	$ 8,382	$ 15,107	$ (837)	$ -	$ 1,262	$ 251	$ (574,569)	$ (554,316)
Total Demand Costs	$ 1,623,361	$ 1,604,045	$ 1,765,392	$ 1,734,550	$ 1,754,525	$ 1,729,847	$ 3,172,095	$ 3,300,823	$ 3,360,828	$ 3,351,764	$ 3,248,305	$ 1,389,093	$ 28,034,630
Demand Costs Transferred to Summer Period	$ (299,371)	$ (299,371)	$ (299,371)	$ (299,371)	$ (299,371)	$ (299,371)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,796,227)
Net Demand Costs For Winter Period	$ 1,323,990	$ 1,304,674	$ 1,466,021	$ 1,435,179	$ 1,455,154	$ 1,430,476	$ 3,172,095	$ 3,300,823	$ 3,360,828	$ 3,351,764	$ 3,248,305	$ 1,389,093	$ 26,238,403
Total Gas Costs	$ 1,375,793	$ 1,362,366	$ 1,464,918	$ 1,454,738	$ 1,456,052	$ 1,431,499	$ 6,520,338	$ 8,939,654	$ 6,709,811	$ 4,239,235	$ 7,480,351	$ 3,012,898	$ 45,447,652

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
May 2012 - April 2013

REDACTED

[redacted]

[redacted]

Commodity Volumes:

BP
Chesapeake
DTE
Distrigas
Emera Energy
Freepoint
Granite
Macquire Cook
JP Morgan
Shell
United
Virginia Power

Subtotal - Commodity Supply

Transportation Volumes
Granite
Portland
Tennessee
Subtotal - Commodity Transportation

Commodity Volume Estimates
Commodity Volume Reversals

Subtotal - Supply

Withdrawal - Underground Storage
Withdrawal - LNG Vaporization
ATV Reconciliation
Off System Sales
Net OBA Adjustment
Company Managed
LNG Boiloff
Transportation Charges
Hedging Costs
Propane
Inventory Finance Charge
Prior Period Adjustment

Subtotal - Other Commodity

Off System & Company Managed Estimates
Off System & Company Managed Reversals

Total Commodity Volumes

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
May 2012 - April 2013

REDACTED

Commodity Volumes:	[redacted]
BP	
Chesapeake	
DTE	
Distrigas	
Emera Energy	
Freepoint	
Granite	
Macquarie Cook	
JP Morgan	
Shell	
United Energy Trading	
Virginia Power	
Subtotal - Commodity Supply	
Transportation Costs:	
Granite	
Portland	
Tennessee	
Subtotal- Commodity Transportation	
Commodity Cost Estimates	
Commodity Cost Reversals	
Subtotal - Supply	
Withdrawal - Underground Storage	
Withdrawal - LNG Vaporization	
ATV Reconciliation Charges	
Off System Sales	
Net OBA Adjustment	
Company Managed	
LNG Boiloff	
Transportation Charges	
Hedging Costs	
Propane	
Inventory Finance Charge	
Prior Period Adjustments	
Subtotal - Other Commodity	
Off System Sales Estimates	
Off System Sales Reversals	
Total Commodity Costs	

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012-2013 WINTER PERIOD RECONCILIATION
SCHEDULE 5: SALES AND TRANSPORTATION VOLUMES
May 2012 - April 2013

New Hampshire	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
Throughput IN													
BTU Factor	1.029	1.031	1.032	1.031	1.029	1.031	1.027	1.031	1.034	1.026	1.024	1.025	
GST Meter Throughput (MCF)	353,621	305,807	274,541	292,293	301,056	396,755	685,674	783,117	1,020,632	899,906	809,744	554,200	6,677,346
Salem Meter (MCF)	14,628	11,332	10,022	10,329	11,898	18,768	40,169	52,707	66,624	58,701	49,074	27,692	371,944
GST Meter Throughput (DTH)	363,876	315,287	283,326	301,354	309,787	409,054	704,187	807,394	1,055,333	923,304	829,178	568,055	6,870,135
Salem Meter (DTH)	15,052	11,683	10,343	10,649	12,243	19,350	41,254	54,341	68,889	60,227	50,252	28,384	382,667
LNG/Propane													
Total Throughput	378,928	326,970	293,669	312,003	322,030	428,404	745,441	861,735	1,124,223	983,531	879,430	596,439	7,252,802
Throughput OUT													
Residential Gas													
Charged	84,825	51,662	37,901	32,967	35,898	51,170	106,027	207,324	272,653	310,432	247,341	183,306	1,621,506
Uncharged Current	27,867	20,751	20,951	20,712	37,187	44,600	90,715	201,459	235,209	169,042	164,975	85,733	1,119,199
Uncharged Prior	-62,968	-27,867	-20,751	-20,951	-20,712	-37,187	-44,600	-90,715	-201,459	-235,209	-169,042	-164,975	-1,096,435
Total Residential Gas	**49,724**	**44,547**	**38,101**	**32,727**	**52,373**	**58,583**	**152,142**	**318,069**	**306,402**	**244,265**	**243,274**	**104,064**	1,644,271
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	86,733	56,312	43,445	43,441	44,774	58,206	112,904	212,122	278,300	322,893	259,181	183,821	1,702,132
Uncharged Current	35,098	25,937	25,556	27,371	32,208	45,529	84,449	196,719	233,922	179,583	176,141	96,076	1,158,589
Uncharged Prior	-65,190	-35,098	-25,937	-25,556	-27,371	-32,208	-45,529	-84,449	-196,719	-233,922	-179,583	-176,141	-1,127,703
Total C/I Gas	**56,642**	**47,151**	**43,064**	**45,256**	**49,611**	**71,528**	**151,824**	**324,392**	**315,503**	**268,554**	**255,739**	**103,755**	1,733,018
Transportation													
Charged	257,702	240,179	218,833	225,833	222,666	251,939	330,576	382,752	450,839	442,935	421,272	347,909	3,793,435
Uncharged Current	90,115	74,961	84,312	88,587	98,502	118,632	166,172	260,422	289,006	208,080	233,085	161,856	1,873,728
Uncharged Prior	-108,333	-90,115	-74,961	-84,312	-88,587	-98,502	-118,632	-166,172	-260,422	-289,006	-208,080	-233,085	-1,820,205
Total Transportation	**239,484**	**225,024**	**228,184**	**230,109**	**232,581**	**272,069**	**378,117**	**477,002**	**479,423**	**362,009**	**446,277**	**276,681**	**3,846,958**
Company Use	**90**	**69**	**77**	**153**	**171**	**110**	**114**	**218**	**263**	**321**	**286**	**210**	**2,082**
Total Throughput OUT	**345,939**	**316,790**	**309,426**	**308,245**	**334,736**	**402,289**	**682,197**	**1,119,680**	**1,101,591**	**875,150**	**945,576**	**484,710**	**7,226,329**
Total Throughput IN	**378,928**	**326,970**	**293,669**	**312,003**	**322,030**	**428,404**	**745,441**	**861,735**	**1,124,223**	**983,531**	**879,430**	**596,439**	**7,252,802**
Difference IN/OUT	32,989	10,180	-15,757	3,758	-12,706	26,115	63,244	-257,946	22,632	108,381	-66,146	111,729	26,474
%													0.37%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED WINTER PERIOD WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2013

PEAK PERIOD - Acct 182.11

	BEGINNING BALANCE	WORKING CAP ALLOWANCE (1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (J / 12)	J = F + I
May 2012	$ (9,592)	411	0.0824%	22	433	(9,159)	(9,375)	3.25%	(25)	(9,184)
June	$ (9,184)	394	0.0824%	0	395	(8,790)	(8,987)	3.25%	(24)	(8,814)
July	$ (8,814)	484	0.0824%	-	484	(8,330)	(8,572)	3.25%	(23)	(8,353)
August	$ (8,353)	440	0.0824%	0	440	(7,913)	(8,133)	3.25%	(22)	(7,935)
September	$ (7,935)	455	0.0824%	(0)	455	(7,480)	(7,708)	3.25%	(21)	(7,501)
October	$ (7,501)	454	0.0824%	0	454	(7,047)	(7,274)	3.25%	(20)	(7,067)
November	$ (7,067)	2,726	0.0824%	(1,056)	1,669	(5,398)	(6,232)	3.25%	(17)	(5,415)
December	$ (5,415)	3,764	0.0824%	(1,962)	1,803	(3,612)	(4,513)	3.25%	(12)	(3,624)
January 2013	$ (3,624)	2,988	0.0824%	(2,550)	438	(3,187)	(3,405)	3.25%	(9)	(3,196)
February	$ (3,196)	2,165	0.0824%	(2,260)	(95)	(3,290)	(3,243)	3.25%	(9)	(3,299)
March	$ (3,299)	3,279	0.0824%	(1,981)	1,298	(2,001)	(2,650)	3.25%	(7)	(2,009)
April	$ (2,009)	1,142	0.0824%	(980)	162	(1,847)	(1,928)	3.25%	(5)	(1,852)
Totals		18,702		(10,767)					(195)	

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Sch 4, page 2 of 12, and multiplying by (9.25/365)*Interest Rate.

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
WINTER PERIOD BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2013

PEAK PERIOD - Acct 182.16

	REVISED BALANCE	BAD DEBT ALLOWANCE (1)	BAD DEBT COLLECTIONS	DEFERRED BALANCE	ENDING BALANCE	BAD DEBT AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D = B + C	E = A + D	F = (A + E) / 2	G	H = F * (G/ 12)	I = E + H
May 2012	(142,934)	16,236	(990)	15,245	(127,689)	(135,312)	3.25%	(366)	(128,055)
June	(128,055)	23,595	(9)	23,586	(104,470)	(116,262)	3.25%	(315)	(104,784)
July	(104,784)	53,673	0	53,673	(51,111)	(77,948)	3.25%	(211)	(51,323)
August	(51,323)	39,450	(1)	39,449	(11,873)	(31,598)	3.25%	(86)	(11,959)
September	(11,959)	11,428	10	11,438	(521)	(6,240)	3.25%	(17)	(538)
October	(538)	15,116	(2)	15,114	14,576	7,019	3.25%	19	14,595
November	14,595	404	(12,532)	(12,128)	2,467	8,531	3.25%	23	2,490
December	2,490	3,149	(23,119)	(19,970)	(17,481)	(7,495)	3.25%	(20)	(17,501)
January 2013	(17,501)	3,016	(29,949)	(26,933)	(44,434)	(30,968)	3.25%	(84)	(44,518)
February	(44,518)	3,322	(26,521)	(23,199)	(67,717)	(56,118)	3.25%	(152)	(67,869)
March	(67,869)	7,254	(23,321)	(16,067)	(83,936)	(75,903)	3.25%	(206)	(84,142)
April	(84,142)	24,056	(11,652)	12,404	(71,738)	(77,940)	3.25%	(211)	(71,949)
Totals		200,697	(128,086)					(1,626)	

(1) Per Docket No. DG 11-69, Bad Debt based on actual write-offs

Attachment C

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Costs
June 2012 - October 2013

		Beginning Balance	Firm Sales and Transportation (therms)	ERC Recovery/Passback Rate	Current ERC Recoveries/ Passbacks	Ending Balance
June 2012	(act)	$ 83,809	2,609,863	$ 0.0051	$ 13,320	$ 70,489
July 2012	(act)	$ 70,489	2,216,245	$ 0.0051	$ 11,311	$ 59,178
August 2012	(act)	$ 59,178	2,169,479	$ 0.0051	$ 11,070	$ 48,108
September 2012	(act)	$ 48,108	2,271,056	$ 0.0051	$ 11,580	$ 36,528
October 2012	(act)	$ 36,528	1,810,786	$ 0.0051	$ 13,841	$ 22,687
November 2012	(act)	$ 258,375 (1)	4,671,698	$ 0.0048 (2)	$ 21,790	$ 236,585
December 2012	(act)	$ 236,585	7,207,188	$ 0.0044	$ 31,713	$ 204,872
January 2013	(act)	$ 204,872	9,133,865	$ 0.0044	$ 40,182	$ 164,689
February 2013	(act)	$ 164,689	9,951,512	$ 0.0044	$ 43,787	$ 120,903
March 2013	(act)	$ 120,903	8,392,918	$ 0.0044	$ 36,929	$ 83,974
April 2013	(act)	$ 83,974	6,244,982	$ 0.0044	$ 27,478	$ 56,494
May 2013	(act)	$ 56,494	2,115,817	$ 0.0044	$ 17,567	$ 38,926
June 2013	(act)	$ 38,926	2,949,527	$ 0.0044	$ 12,978	$ 25,948
July 2013	(est)	$ 25,948	2,163,584	$ 0.0044	$ 9,520	$ 16,428
August 2013	(est)	$ 16,428	2,188,437	$ 0.0044	$ 9,629	$ 6,799
September 2013	(est)	$ 6,799	2,362,851	$ 0.0044	$ 10,397	$ (3,597)
October 2013	(est)	$ (3,597)	3,452,777	$ 0.0044	$ 15,192	$ (18,789)

(1) November Beginning Balance includes $235,688 amortization from all prior years at 1/7 of annual costs. (See Section 4.7 of Tariff.)

(2) November Current ERC Recoveries/Passbacks reflect an Average ERC Rate based on actual Firm Sales and Transportation (therms) at $0.0044 and actual Firm Sales and Transportation (therms) at $0.0051.

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
RLIARA Reconciliation
May 2012 - October 2013

		Beginning Balance A	Program Costs B	Regulatory Assessments C	RLIARA Recoveries D	Ending Balance E = A + B +C - D	Average Monthly Balance F = (A +E) / 2	Interest Rate G	Interest H = F * (G / 12)	Ending Balance w/Interest I = E + H
May 2012	Actual	$ (61,920)	$ 24,071	$ 137,625 (1)	$ 25,180	$ 74,597	$ 6,338	3.25%	$ 113 (2)	$ 74,710
June 2012	Actual	$ 74,710	$ 16,696	$ 15,861	$ 23,230	$ 84,037	$ 79,373	3.25%	$ 215	$ 84,252
July 2012	Actual	$ 84,252	$ 14,333	$ 6,545	$ 19,733	$ 85,397	$ 84,824	3.25%	$ 230	$ 85,627
August 2012	Actual	$ 85,627	$ 12,968	$ 6,545	$ 19,314	$ 85,825	$ 85,726	3.25%	$ 232	$ 86,057
September 2012	Actual	$ 86,057	$ 11,531	$ 6,545	$ 20,206	$ 83,927	$ 84,992	3.25%	$ 230	$ 84,157
October 2012	Actual	$ 84,157	$ 15,146	$ 12,814	$ 24,140	$ 87,978	$ 86,068	3.25%	$ 233	$ 88,211
November 2012	Actual	$ 88,211	$ 17,338	$ 12,814	$ 45,950	$ 72,414	$ 80,312	3.25%	$ 218	$ 72,632
December 2012	Actual	$ 72,632	$ 31,046	$ 12,814	$ 74,946	$ 41,547	$ 57,089	3.25%	$ 155	$ 41,702
January 2013	Actual	$ 41,701	$ 37,289	$ 14,735	$ 94,979	$ (1,254)	$ 20,223	3.25%	$ 55	$ (1,199)
February 2013	Actual	$ (1,199)	$ 46,733	$ 14,735	$ 103,556	$ (43,287)	$ (22,243)	3.25%	$ (60)	$ (43,347)
March 2013	Actual	$ (43,347)	$ 41,916	$ 14,735	$ 87,287	$ (73,984)	$ (58,665)	3.25%	$ (159)	$ (74,143)
April 2013	Actual	$ (74,143)	$ 35,007	$ 14,735	$ 64,949	$ (89,350)	$ (81,746)	3.25%	$ (221)	$ (89,571)
May 2013	Actual	$ (89,571)	$ 22,767	$ 14,734	$ 41,527	$ (93,596)	$ (91,584)	3.25%	$ (248)	$ (93,844)
June 2013	Actual	$ (93,844)	$ 15,692	$ 14,734	$ 30,672	$ (94,090)	$ (93,967)	3.25%	$ (254)	$ (94,344)
July 2013	Est.	$ (94,344)	$ 30,194	$ 14,734	$ 19,733	$ (69,148)	$ (81,746)	3.25%	$ (221)	$ (69,369)
August 2013	Est.	$ (69,369)	$ 10,196	$ 14,734	$ 19,314	$ (63,753)	$ (66,561)	3.25%	$ (180)	$ (63,933)
September 2013	Est.	$ (63,933)	$ 18,076	$ 14,734	$ 20,206	$ (51,328)	$ (57,630)	3.25%	$ (156)	$ (51,484)
October 2013	Est.	$ (51,484)	$ 27,961	$ 14,734	$ 24,140	$ (32,928)	$ (42,206)	3.25%	$ (114)	$ (33,043)

(1) May 2012 Regulatory Assessment includes Assessments from August 1, 2011 to April 30, 2012.

(2) Includes interest true up from August 1, 2011 to April 30, 2012.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2012 - 2013

Attachment E
Page 1 of 2

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL
Forecast Calendar Month Sales	351,075	516,209	593,135	517,170	451,952	301,052	2,730,593
Actual Sales	218,931	419,446	550,949	633,325	506,523	367,124	2,696,297
Difference	(132,144)	(96,763)	(42,186)	116,155	54,571	66,072	(34,296)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	321,945	544,407	596,158	592,336	406,398	210,270	2,671,513
Actual Sales	218,931	419,446	550,949	633,325	506,523	367,124	2,696,297
Weather Variance	103,014	124,961	45,209	(40,989)	(100,125)	(156,854)	(24,784)
Total Variance Excluding Weather	(29,130)	28,198	3,023	75,166	(45,554)	(90,782)	(59,080)
(excl weather effect)							
Variance-difference due to meter count							(73,633)
-difference in load pattern							39,277
SALES							(34,356)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2012 - 2013

Attachment E
Page 2 of 2

	NORMAL MMBtu			METERS		
	2012-13 Forecast	2012-13 Actual	Difference	2012-13 Forecast	2012-13 Actual	Difference
Res Heat	1,309,485	1,304,880	(4,605)	129,194	129,588	394
Res General	24,779	22,200	(2,579)	8,796	8,736	(60)
Total Res	1,334,264	1,327,080	(7,184)	137,990	138,324	334
G-40	671,795	652,643	(19,152)	26,627	26,448	(179)
G-50	96,091	72,097	(23,994)	5,570	4,621	(949)
G-41	460,904	432,653	(28,251)	2,426	2,228	(198)
G-51	113,643	116,158	2,515	996	940	(56)
G-42	45,743	72,427	26,684	105	55	(50)
G-52	8,213	23,239	15,026	24	51	27
Total C & I	1,396,389	1,369,216	(27,173)	35,748	34,343	(1,405)
Total Company	2,730,653	2,696,297	(34,356)	173,738	172,667	(1,071)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2012-13 Forecast	2012-13 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.14	10.07	(0.07)	3,994	(8,599)	(4,605)	-0.35%
Res General	2.82	2.54	(0.28)	(169)	(2,410)	(2,579)	-10.41%
Total Res	12.95	12.61	(0.34)	3,824	(11,008)	(7,184)	-0.54%
G-40	25.23	24.68	(0.55)	(4,523)	(14,629)	(19,152)	-2.85%
G-50	17.25	15.60	(1.65)	(16,366)	(7,628)	(23,994)	-24.97%
G-41	190.00	194.19	4.19	(37,582)	9,331	(28,251)	-6.13%
G-51	114.07	123.57	9.50	(6,415)	8,930	2,515	2.21%
G-42	435.13	1,316.86	881.73	(21,811)	48,495	26,684	58.33%
G-52	342.21	455.66	113.46	9,240	5,786	15,026	182.95%
Total C & I	39.06	39.87	0.81	(77,458)	50,285	(27,173)	-1.95%
Total Company	15.72	15.62	(0.10)	(73,633)	39,277	(34,356)	-1.26%

Schedule 16

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
Residential Low Income Assistance and Regulatory Assessment Costs (RLIARA)

		Customer Charge	First Block	Last Block	Total
1	**Peak Period**				
2	R-5 Base Rates	$13.73	$0.4410	$0.3829	
3	R-10 Rate at 40% of R5	$5.50	$0.1764	$0.1532	
4	Program Subsidy	$8.23	$0.2646	$0.2297	
5	Average Annual Therms		252	512	764
6					
7	Peak Period Subsidy	$49.37	$66.71	$117.60	$233.68
8					
9	**Off Peak Period**				
10	R-5 Base Rates	$13.73	$0.4410	$0.4410	
11	R10 Rate at 40% of R5	$5.50	$0.1764	$0.1764	
12	Program Subsidy	$8.23	$0.2646	$0.2646	
13	Average Annual Therms		167	42	209
14					
15	Off Peak Period Subsidy	$49.37	$44.24	$11.06	$104.67
16					
17	Estimated Annual Subsidy				$338.35
18					
19	Number of Estimated 2013/14 Participants				1,120
20					
21	Annual Subsidy times Number of Participants (Ln 17 *Ln 19)				$378,893
22	Prior Year Ending Balance - RLIARA Page 2				($76,330)
23	Estimated Annual Administrative Costs				$0
24	Estimated 2014 CY 12 month Regulatory Assessment (Based off of NHPUC invoice dated August 8, 2013)				$117,335
25	Total Program Costs				$419,898
26					
27	Estimated weather normalized firm therms billed for				
28	the twelve months ended 10/31/14 sales and transportation				65,105,908
29	(Attachment 2 to Schedule 10B, Revised Page 1 of 3, Line 41, "Total Division"				
30	subtract Line 41 "Special Contracts").				
31	**Total Residential Low Income Assistance and Regulatory Assessment Costs Charge**				**$0.0064**

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
NOVEMBER 2012 THROUGH OCTOBER 2013
RESIDENTIAL LOW INCOME ASSISTANCE AND REGULATORY ASSESSMENT COSTS (RLIARA) RECONCILIATION

											(Estimate)	(Estimate)	(Estimate)	(Estimate)
1	**FOR THE MONTH OF:**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Total**
2	**DAYS IN MONTH**	30	31	31	28	31	30	31	30	31	31	30	31	365
3														**Average**
4	RLIA Participant Count	931	1,084	1,055	1,253	1,302	1,293	1,240	1,140	1,122	1,105	964	949	1,120
5														**Total**
6	Beginning Balance	$88,221	$72,813	$41,710	($1,189)	($43,332)	($74,131)	($89,556)	($93,835)	($94,331)	($89,991)	($84,454)	($80,029)	$88,221
7														
8	Add: Actual Costs	$17,514	$30,871	$37,289	$46,733	$41,916	$35,007	$22,767	$15,692	$13,262	$10,600	$10,749	$11,515	$293,916
9														
10	Add: Regulatory Assessments	$12,814	$12,814	$14,735	$14,735	$14,735	$14,734	$14,734	$14,734	$14,734	$3,820	$3,820	$3,820	$140,230
11														
12	Less: Collected Revenue	$45,950	$74,946	$94,979	$103,556	$87,287	$64,949	$41,527	$30,672	$23,402	$8,642	$9,925	$11,419	($597,255)
13														
14	Add: Administrative and Start Up Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15														
16	Ending Balance Pre-Interest	$72,599	$41,554	($1,244)	($43,277)	($73,969)	($89,338)	($93,582)	($94,080)	($89,737)	($84,214)	($79,810)	($76,114)	
17														
18	Month's Average Balance	($18,120)	$57,184	$20,233	($22,233)	($58,650)	($81,734)	($91,569)	($93,958)	($92,034)	($87,103)	($82,132)	($78,072)	
19														
20	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%	
21														
22	Interest Applied	$214.21	$156.93	$55.85	($55.43)	($161.89)	($218.33)	($252.76)	($250.98)	($254.04)	($240.43)	($219.39)	($215.50)	($1,442)
23														
24	Ending Balance	$72,813	$41,710	($1,189)	($43,332)	($74,131)	($89,556)	($93,835)	($94,331)	($89,991)	($84,454)	($80,029)	**($76,330)**	($76,330)

Note- May and June 2012 Interest Applied line items includes true ups for Regulatory Assessment Costs.

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
NOVEMBER 2012 THROUGH OCTOBER 2013
RESIDENTIAL LOW INCOME ASSISTANCE AND REGULATORY ASSESSMENT COSTS (RLIARA) RECONCILIATION
Calculation of Non-Distribution Revenues of the NHPUC Assessment

				CY 2012 PUC assessment bills			
Month of Payment/(accrued payment):				January	April	Aug	Oct
				Q1	Q2	Q3	Q4
	2012 Revenue		% to total	$ 78,516.00	$ 78,514.00	$ 20,353.00	$ 58,588.00
Customer Charge (1)	$ 5,926,646	(1)	11.68%				
Distribution First Step (1)	$ 9,738,006	(1)	19.18%				
Distribution Excess (1)	$ 4,370,714	(1)	8.61%				
Demand Cost of Gas (2)	$ 12,601,612	(2)	24.83%				
Commodity Cost of Gas (2)	$ 15,085,782	(2)	29.72%				
Reconciliation Costs (2)	$ 3,434	(2)	0.01%				
Working Captial (2)	$ (4,414)	(2)	-0.01%				
Bad Debt (2)	$ 305,925	(2)	0.60%				
Production & Storage Capacity (2)	$ 287,575	(2)	0.57%				
Miscellaneous Overhead (2)	$ 361,523	(2)	0.71%				
Demand Supplier Refund (2)	$ (59,662)	(2)	-0.12%				
Commodity Supplier Refund (2)	$ (5,353)	(2)	-0.01%				
Residential Low Income Assistance Program (1)	$ 413,940	(1)	0.82%				
Demand Side Management (1)	$ 1,022,928	(1)	2.02%				
Environmental Response Cost (1)	$ 279,054	(1)	0.55%				
Rate Case Expense (1)	$ 117,889	(1)	0.23%				
Recon of Permanent Changes (1)	$ 315,290	(1)	0.62%				
Total	$ 50,760,889		100.00%				
	$50,760,889						
Distribution Revenue, Including LDAC (1)	$ 22,184,467	(1)	**43.70%**				
CGAC Revenue (2)	$ 28,576,422	(2)	**56.30%**				
	$ 50,760,889		100.00%				
Distribution Portion of the PUC Assessment	-			**Q1**	**Q2**	**Q3**	**Q4**
Quarterly Amount	**Included in Base**			$ 34,311.49	$ 34,310.62	$ 8,894.26	$ 25,602.96
Monthly Amount				$ 11,437.16	$ 11,436.87	$ 2,964.75	$ 8,534.32
NonDistribution Portion of the PUC Assessment							
Quarterly Amount				$ 44,204.51	$ 44,203.38	$ 11,458.74	$ 32,985.04
Monthly Amount				$ 14,734.84	$ 14,734.46	$ 3,819.58	$ 10,995.01
*Allocations are based on Prior Year Revenue				Line 10 Jan- Mar 2012	Line 10 Apr- June 2012	Line 10 Jul- Oct 2012	

Northern Utilities, Inc. -- New Hampshire Division

Energy Efficiency Budget

	Residential	Low-Income	Gen Service	Total
August-13	$27,993	$2,158	$69,881	$100,033
September-13	$15,447	$7,006	$70,381	$92,835
October-13	$13,997	$7,006	$34,941	$55,944
November-13	$13,997	$7,006	$46,587	$67,590
December-13	$70,044	$33,630	$47,087	$150,762
January-14	$28,850	$11,603	$33,387	$73,840
February-14	$34,620	$13,924	$44,516	$93,060
March-14	$40,390	$16,245	$34,887	$91,522
April-14	$40,390	$16,245	$55,645	$112,280
May-14	$28,850	$11,603	$33,387	$73,840
June-14	$100,423	$39,452	$79,403	$219,278
July-14	$23,080	$9,283	$22,258	$54,621
August-14	$57,700	$23,207	$66,774	$147,681
September-14	$31,183	$11,603	$68,274	$111,061
October-14	$28,850	$11,603	$33,387	$73,840
Total	$555,815	$221,577	$740,795	$1,518,187

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

	Residential	Low-Income	Gen Service	Total
August-13	$28,368	0	$71,665	$100,033
September-13	$16,499	0	$76,336	$92,835
October-13	$15,626	0	$40,318	$55,944
November-13	$15,438	0	$52,152	$67,590
December-13	$79,909	0	$70,853	$150,762
January-14	$32,269	0	$41,572	$73,840
February-14	$39,122	0	$53,938	$93,060
March-14	$45,379	0	$46,143	$91,522
April-14	$45,009	0	$67,270	$112,280
May-14	$31,542	0	$42,298	$73,840
June-14	$108,324	0	$110,954	$219,278
July-14	$24,790	0	$29,831	$54,621
August-14	$61,503	0	$86,178	$147,681
September-14	$33,181	0	$77,880	$111,061
October-14	$30,990	0	$42,851	$73,840
Total	$607,948	$0	$910,238	$1,518,187

DSM Charge Factor Calculation

DSM Charge Factors for Residential Customers

DSM Reconciliation Adjustment	($1,077)	Schedule 16 DSM B Nov '13 - Oct '14 Totals- November 2013 Beginning Balance
DSM Costs	$498,377	Schedule 16 DSM B Nov '13 - Oct '14 Totals- Column 2
DSM Share Holder Incentive	$46,416	Schedule 16 DSM B Nov '13 - Oct '14 Totals- Column 3
DSM Low-Income Costs	$49,079	Schedule 16 DSM B Nov '13 - Oct '14 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$3,721	Schedule 16 DSM B Nov '13 - Oct '14 Totals- Column 5
Total	$596,516	
Forecasted Annual Throughput Volumes for Residential Customers	17,061,674	Schedule 16 DSM B Nov '13 - Oct '14 Totals- Column 6
Conservation Charge Factor for Residential Customers	**$0.0350**	

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

DSM Reconciliation Adjustment	($95,655)	Schedule 16 DSM C Nov '13 - Oct '14 Totals- November 2013 Beginning Balance
DSM Costs	$565,593	Schedule 16 DSM C Nov '13 - Oct '14 Totals- Column 2
DSM Share Holder Incentive	$44,679	Schedule 16 DSM C Nov '13 - Oct '14 Totals- Column 3
DSM Low-Income Costs	$156,327	Schedule 16 DSM C Nov '13 - Oct '14 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$12,045	Schedule 16 DSM C Nov '13 - Oct '14 Totals- Column 5
Total	$682,988	
Forecasted Annual Throughput Volumes for C&I Customers	48,044,234	Schedule 16 DSM C Nov '13 - Oct '14 Totals- Column 6
Conservation Charge Factor for C&I Customers	**$0.0142**	

Northern Utilities, Inc.

New Hampshire Division

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

To Be Effective November 1, 2013 through October 31, 2014

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-12	Actual	($35,223)	$0.0333	$10,977	$12,480	$3,231	$1,997	$455	($28,039)	($31,631)	3.25%	($87)	($28,126)	329,672	31
September-12	Actual	($28,126)	$0.0333	$11,892	$77,532	$3,231	$2,677	$233	$43,654	$7,764	3.25%	$21	$43,675	358,975	30
October-12	Actual	$43,675	$0.0333	$17,102	$42,714	$3,231	$3,256	$283	$76,057	$59,866	3.25%	$165	$76,223	511,696	31
November-12	Actual	$76,223	$0.0403	$38,244	$48,769	$3,231	$1,474	$128	$91,581	$83,902	3.25%	$224	$91,805	1,060,270	30
December-12	Actual	$91,805	$0.0403	$83,552	$78,870	$3,231	$9,565	$832	$100,751	$96,278	3.25%	$266	$101,017	2,073,245	31
January-13	Actual	$101,017	$0.0403	$109,876	$92,199	$3,643	$1,149	$100	$88,232	$94,624	3.25%	$261	$88,491	2,726,532	31
February-13	Actual	$88,491	$0.0403	$125,104	$43,510	$3,643	$6,144	$534	$17,218	$52,855	3.25%	$132	$17,350	3,104,322	28
March-13	Actual	$17,350	$0.0403	$99,678	$65,514	$3,643	$3,816	$332	($9,023)	$4,164	3.25%	$11	($9,011)	2,473,413	31
April-13	Actual	($9,011)	$0.0403	$73,873	$48,597	$3,643	$2,440	$212	($27,993)	($18,502)	3.25%	($49)	($28,042)	1,833,057	30
May-13	Actual	($28,042)	$0.0403	$38,301	$22,514	($8,170)	$222	$19	($51,759)	($39,901)	3.25%	($810)	($52,569)	950,389	31
June-13	Actual	($52,569)	$0.0403	$22,535	$38,967	$3,643	$1,523	$132	($30,838)	($41,704)	3.25%	($111)	($30,950)	950,389	30
July-13	Actual	($30,950)	$0.0403	$13,943	$20,486	$3,643	$2,350	$204	($18,209)	($24,579)	3.25%	($68)	($18,277)	559,280	31
August-13	Forecast	($18,277)	$0.0403	$13,935	$27,993	$3,643	$374	$87	($115)	($9,196)	3.25%	($25)	($140)	345,787	31
September-13	Forecast	($138)	$0.0403	$13,289	$15,447	$3,643	$1,052	$110	$6,824	$3,343	3.25%	$9	$6,833	329,751	30
October-13	Forecast	$6,833	$0.0403	$27,357	$13,997	$3,643	$1,629	$170	($1,085)	$2,874	3.25%	$8	($1,077)	678,840	31
November-13	Forecast	**($1,077)**	$0.0350	$33,707	$13,997	$3,643	$1,441	$151	($15,552)	($8,315)	3.25%	($22)	($15,574)	964,105	30
December-13	Forecast	($15,574)	$0.0350	$74,696	$70,044	$3,643	$9,865	$215	($6,504)	($11,039)	3.25%	($30)	($6,534)	2,136,463	31
January-14	Forecast	($6,534)	$0.0350	$104,605	$28,850	$3,913	$3,419	$421	($74,536)	($40,535)	3.25%	($112)	($74,648)	2,991,937	31
February-14	Forecast	($74,648)	$0.0350	$112,962	$34,620	$3,913	$4,502	$462	($144,112)	($109,380)	3.25%	($273)	($144,385)	3,230,961	28
March-14	Forecast	($144,385)	$0.0350	$93,615	$40,390	$3,913	$4,989	$439	($188,269)	($166,327)	3.25%	($459)	($188,728)	2,677,602	31
April-14	Forecast	($188,728)	$0.0350	$66,194	$40,390	$3,913	$4,619	$407	($205,593)	($197,161)	3.25%	($527)	($206,120)	1,893,284	30
May-14	Forecast	($206,120)	$0.0350	$31,747	$28,850	$3,913	$2,692	$332	($202,080)	($204,100)	3.25%	($563)	($202,643)	908,024	31
June-14	Forecast	($202,643)	$0.0350	$19,292	$100,423	$3,913	$7,901	$286	($109,411)	($156,027)	3.25%	($417)	($109,828)	551,783	30
July-14	Forecast	($109,828)	$0.0350	$14,185	$23,080	$3,913	$1,710	$263	($95,047)	($102,437)	3.25%	($283)	($95,330)	405,724	31
August-14	Forecast	($95,330)	$0.0350	$12,413	$57,700	$3,913	$3,803	$234	($42,092)	($68,711)	3.25%	($190)	($42,282)	355,042	31
September-14	Forecast	($42,282)	$0.0350	$13,599	$31,183	$3,913	$1,998	$246	($18,540)	($30,411)	3.25%	($81)	($18,622)	388,974	30
October-14	Forecast	($18,622)	$0.0350	$19,501	$28,850	$3,913	$2,140	$264	($2,956)	($10,789)	3.25%	($30)	($2,986)	557,777	31
Nov 13 thru Oct 14 Totals				$596,516	$498,377	$46,416	$49,079	$3,721						17,061,674	

Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 1 of 3, Lines 26 through 41 filed on September 16, 2013 in this Cost of Gas Docket.

Northern Utilities, Inc.

New Hampshire Division

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

To Be Effective November 1, 2013 through October 31, 2014

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-12	Actual	($118,620)	$0.0126	$23,181	$11,593	$2,870	$12,586	$1,094	($113,657)	($116,138)	3.25%	($321)	($113,978)	1,839,807	31
September-12	Actual	($113,978)	$0.0126	$24,091	$13,592	$2,870	$14,261	$1,240	($106,105)	($110,042)	3.25%	($294)	($106,399)	1,912,081	30
October-12	Actual	($106,399)	$0.0126	$27,707	$12,477	$2,870	$13,992	$1,217	($103,551)	($104,975)	3.25%	($290)	($103,840)	2,199,004	31
November-12	Actual	($103,840)	$0.0118	$43,509	$21,720	$2,870	$5,021	$437	($117,301)	($110,571)	3.25%	($295)	($117,596)	3,611,427	30
December-12	Actual	($117,596)	$0.0118	$60,581	$51,895	$2,870	$23,685	$2,060	($97,667)	($107,632)	3.25%	($297)	($97,959)	5,133,943	31
January-13	Actual	($97,959)	$0.0118	$75,587	$40,960	$3,589	$2,701	$235	($126,060)	($112,009)	3.25%	($309)	($126,369)	6,007,712	31
February-13	Actual	($126,369)	$0.0118	$80,797	$19,070	$3,589	$13,552	$1,178	($169,777)	($148,073)	3.25%	($369)	($170,146)	5,727,655	29
March-13	Actual	($170,146)	$0.0118	$69,851	$13,680	$3,589	$9,133	$794	($212,800)	($191,473)	3.25%	($529)	($213,328)	4,958,839	31
April-13	Actual	($213,328)	$0.0118	$52,060	$21,540	$3,589	$5,872	$511	($233,876)	($223,602)	3.25%	($597)	($234,474)	3,502,134	30
May-13	Actual	($234,474)	$0.0118	$35,897	$22,050	$8,216	$734	$64	($239,307)	($236,890)	3.25%	($497)	($239,804)	2,598,065	31
June-13	Actual	($239,804)	$0.0118	$28,205	$18,101	$3,589	$6,509	$566	($239,244)	($239,524)	3.25%	($640)	($239,883)	2,093,258	30
July-13	Actual	($239,883)	$0.0118	$22,467	$24,931	$3,589	$12,940	$1,125	($219,764)	($229,824)	3.25%	($634)	($220,398)	1,837,235	31
August-13	Forecast	($220,398)	$0.0118	$23,181	$69,881	$3,589	$1,784	$646	($167,679)	($194,038)	3.25%	($536)	($168,214)	1,862,899	31
September-13	Forecast	($168,214)	$0.0118	$24,091	$70,381	$3,589	$5,955	$623	($111,757)	($139,986)	3.25%	($374)	($112,131)	1,867,372	30
October-13	Forecast	($112,131)	$0.0118	$27,707	$34,941	$3,589	$5,377	$563	($95,368)	($103,750)	3.25%	($286)	($95,655)	2,240,979	31
November-13	Forecast	**($95,655)**	$0.0142	$43,509	$46,587	$3,589	$5,565	$582	($82,840)	($89,247)	3.25%	($238)	($83,078)	3,623,148	30
December-13	Forecast	($83,078)	$0.0142	$60,581	$47,087	$3,589	$23,766	$518	($68,698)	($75,888)	3.25%	($209)	($68,907)	5,518,807	31
January-14	Forecast	($68,907)	$0.0142	$102,684	$33,387	$3,750	$8,185	$1,009	($125,261)	($97,084)	3.25%	($268)	($125,529)	7,223,250	31
February-14	Forecast	($125,529)	$0.0142	$105,077	$44,516	$3,750	$9,422	$968	($171,950)	($148,740)	3.25%	($371)	($172,321)	7,391,577	28
March-14	Forecast	($172,321)	$0.0142	$93,965	$34,887	$3,750	$11,256	$991	($215,402)	($193,862)	3.25%	($535)	($215,937)	6,609,877	31
April-14	Forecast	($215,937)	$0.0142	$66,933	$55,645	$3,750	$11,625	$1,023	($210,827)	($213,382)	3.25%	($570)	($211,397)	4,708,315	30
May-14	Forecast	($211,397)	$0.0142	$41,175	$33,387	$3,750	$8,911	$1,098	($205,425)	($208,411)	3.25%	($575)	($206,000)	2,896,438	31
June-14	Forecast	($206,000)	$0.0142	$33,404	$79,403	$3,750	$31,551	$1,144	($123,557)	($164,779)	3.25%	($440)	($123,997)	2,349,775	30
July-14	Forecast	($123,997)	$0.0142	$29,593	$22,258	$3,750	$7,573	$1,167	($118,842)	($121,420)	3.25%	($335)	($119,177)	2,081,728	31
August-14	Forecast	($119,177)	$0.0142	$29,697	$66,774	$3,750	$19,404	$1,196	($57,751)	($88,464)	3.25%	($244)	($57,995)	2,088,998	31
September-14	Forecast	($57,995)	$0.0142	$30,369	$68,274	$3,750	$9,606	$1,184	($5,550)	($31,773)	3.25%	($85)	($5,635)	2,136,271	30
October-14	Forecast	($5,635)	$0.0142	$20,130	$33,387	$3,750	$9,464	$1,166	$22,002	$8,183	3.25%	$23	$22,025	1,416,049	31
Nov 12 thru Oct 13 Totals				$657,117	$565,593	$44,679	$156,327	$12,045						48,044,233	

Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 1 of 3, Lines 26 through 41 filed on September 16, 2013 in this Cost of Gas Docket.

Note- May 2013 DSM SHI includes a LI Allocation adjustment for 2012 trueup.

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE

November 1, 2013 through October 31, 2014

Total ERC Costs for the Period	$170,394	
Less Current Under Collection (Estimated)	$16,060	(See page 2 of 2)
Less Total RCE/RPC Under Collection from Docket No. DG 11-069	$24,951	
Total ERC Cost to be Recovered	$211,405	
Forcasted Firm Sales & Firm Transportation Volumes (Attachment 2 to Schedule 10B, Revised Page 1 of 3, Line 41, "Total Division" subtract Line 41 "Special Contracts").	65,105,908	
ERC Recovery Rate	**$0.0032**	

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	$59,178	$11,070		$48,108
September	Actual	$48,108	$11,580		$36,528
October	Actual	$36,528	$13,841		$22,687
November-'12	Actual	$22,687	$21,790	$235,688	$236,585
December	Actual	$236,585	$31,713		$204,872
January- '13	Actual	$204,872	$40,182		$164,689
February	Actual	$164,689	$43,786		$120,903
March	Actual	$120,903	$36,927		$83,977
April	Actual	$83,977	$27,479		$56,497
May	Actual	$56,497	$17,567		$38,930
June	Actual	$38,930	$12,978		$25,952
July	Actual	$25,952	$9,890		$16,060

Schedule 17

Northern Utilities, Inc.
New Hampshire Division
Schedule 17
Page 1 of 1

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDIATION ADJUSTMENT CLAUSE COMPLIANE FILING
2012-2013 ENVIORMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES

Line	Description	Total	11/07 - 10/08	11/08 - 10/09	11/09 - 10/10	11/10 - 10/11	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14 10/15	11/15-10/16	11/16-10/17	11/17-10/18	11/18-10/19	11/19-10/20
	ENVIRONMENTAL RESPONSE COST (ERC)														
1	July 06 - June 07 Expenses Amortization (1/7)	$ 186,804	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686						
2	July 07 - June 08 Expenses Amortization (1/7)	$ 232,960		$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280					
3	July 08 - June 09 Expenses Amortization (1/7)	$ 127,728			$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247				
4	July 09 - June 10 Expenses Amortization (1/7)	$ 189,634				$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091			
5	July 10 - June 11 Expenses Amortization (1/7)	$ 121,209					$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316		
6	July 11 - June 12 Expenses Amortization (1/7)	$ 159,020						$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	
7	July 12 - June 13 Expenses Amortization (1/7)	$ 175,406							$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058
8	Subtotal (Line 1 through Line 7)	$ 1,192,761	$ 26,686	$ 59,966	$ 78,213	$ 105,304	$ 122,619	$ 145,336	$ 170,394	$ 143,708	$ 110,428	$ 92,181	$ 65,091	$ 47,775	$ 25,058
9	Add: Excess amortization from prior years (from schedule 5, Line 10)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Less: Excess amortization to be deferred (from schedule 5, Line 9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total Enviromental Response cost to be recovered (ERC)	$ 1,192,761	$ 26,686	$ 59,967	$ 78,213	$ 105,304	$ 122,619	$ 145,336	$ 170,394	$ 143,708	$ 110,428	$ 92,181	$ 65,091	$ 47,775	$ 25,058
13	July 2006 - June 2007 Unamortized beginning balance		$ 186,804	$ 160,118	$ 133,431	$ 106,745	$ 80,059	$ 53,373	$ 26,686						
14	July 2007 - June 2008 Unamortized beginning balance			$ 232,960	$ 199,680	$ 166,400	$ 133,120	$ 99,840	$ 66,560	$ 33,280					
15	July 2008 - June 2009 Unamortized beginning balance				$ 127,728	$ 109,481	$ 91,234	$ 72,987	$ 54,741	$ 36,494	$ 18,247				
16	July 2009 - June 2010 Unamortized beginning balance					$ 189,634	$ 162,544	$ 135,453	$ 108,362	$ 81,272	$ 54,181	$ 27,091			
17	July 2010 - June 2011 Unamortized beginning balance						$ 121,209	$ 103,893	$ 86,578	$ 69,262	$ 51,947	$ 34,631	$ 17,316		
18	July 2011 - June 2012 Unamortized beginning balance							$ 159,020	$ 136,303	$ 113,586	$ 90,869	$ 68,151	$ 45,434	$ 22,717	
19	July 2012 - June 2013 Unamortized beginning balance														
20	Total Unamortized beginning balance		$ 186,804	$ 393,078	$ 460,839	$ 572,260	$ 588,166	$ 624,566	$ 479,230	$ 333,893	$ 215,243	$ 129,873	$ 62,750	$ 22,717	
21	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)														
22	INSURANCE/3RD PARTY RECOVERIES (IR)														
23	UNDER/OVER Recovery from previous year														
24	**Total of Lines 15, 16, 17, 18**		$ 186,804	$ 393,078	$ 460,839	$ 572,260	$ 588,166	$ 624,566	$ 479,230	$ 333,893	$ 215,243	$ 129,873	$ 62,750	$ 22,717	

Schedule 18

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

November 2013 through October 2014

		MDQ	Max Swing	% MDQ
1	New Hampshire Underground	16,842	3,532	20.97%
2	LNG	0	0	0.00%
3	Propane	0	0	0.00%

		% MDQ	Costs	Balancing Costs	% Allocated	Allocated Costs
4	New Hampshire Underground					
5	Del., Res., and Transp.	20.97%	$11,690,731	$2,451,616	0.20%	$4,920
6	Capacity	20.97%	$1,396,256	$292,803	35.64%	$104,350
7	LNG	0.00%	$95,030	$0	0.00%	$0
8	Propane	0.00%	$119,564	$0	0.00%	$0
9	Total		$13,301,581	$2,744,419		$109,270
10	Annual Sum of Absolute Swings					142,624
11	Balancing Rate Per MMBtu Swing					**$0.77**

Note: LNG and LP MDQ allocated based on New Hampshie's current PR-Allocator percentage. 47.24%

Northern Utilities, Inc.
Calculation of Balancing Charge
Costs of Balancing Resources
November 2012 through October 2013

			Northern Capacity	Division Allocated	Rate	Months	Costs
1	**New Hampshire**						
2	El Paso FS Storage						
3	Capacity	Cap	259,337	122,511	$0.0211	12	$31,020
4	Deliverability	Del	4,243	2,004	$1.5400	12	$37,041
5	Firm Transportation-Tenn	Trans	2,653	1,253	$8.4896	12	$127,678
6	Firm Transportation-GSGT	Trans	2,653	1,253	$3.5729	12	$53,734
7	Total						$249,473
8							
9	W-10 Storage						
10	W-10	Cap	34,000	16,062	$ 7.0833	12	$1,365,236
11	PNGTS	Trans	33,000	15,589	$ 76.4666	5	$5,960,266
12	Vector - In	Trans	17,172	8,112	$ 7.6042	12	$740,228
13	Vector -Out	Trans	17,086	8,071	$ 5.0413	5	$203,452
14	TCPL	Trans	34,000	16,062	$ 20.2343	12	$3,899,943
15	Firm Transportation-GSGT	Trans	33,000	15,589	$ 3.5729	12	$668,389
16	Total						$12,837,513
17	LNG						
18	NH		10,000	4,724			$95,030
18	ME		10,000	5,276			$201,164
19	Total						$201,164
20	Propane						
21	Capacity						
22	NH		4,000	1,890			$226,619
22	ME		4,000	2,110			$253,100
23	Total						$479,719
24							
25	New Hampshire Summary						
26		Del	4,243	2,004			$37,041
27		Res	0	0			$0
28		Trans	139,564	65,930			$11,653,690
29		Cap	293,337	138,572			$1,396,256
30		Total	437,144	206,507			$13,086,987
31	Gate Station Delivery		35,653	16,842			

Northern Utilities, Inc.
Calculation of Suppliler Balancing Charge

Derivation of Absolute Swings
May 2000 through April 2001
Summary

		Sum Positive Swings		Sum Negative Swings		Sum LP / LNG Swings		ABS all Swings		Total
		Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	ABS Swings
1	May	1,060	1,484	8,125	1,162	0	0	9,185	2,646	11,832
2	June	0	28	1,213	5,553	0	0	1,213	5,582	6,794
3	July	1,125	0	0	0	0	0	1,125	0	1,125
4	Aug	45	0	99	1,027	0	0	145	1,027	1,172
5	Sept	0	0	301	11,279	0	0	301	11,279	11,580
6	Oct	1,196	123	2,821	26,853	0	0	4,017	26,976	30,993
7	Nov	384	0	3,976	7,620	(2,382)	(2,539)	6,743	10,159	16,901
8	Dec	0	0	7,956	12,177	0	0	7,956	12,177	20,133
9	Jan	0	0	1,873	174	(423)	(13,355)	2,296	13,530	15,826
10	Feb	0	0	2,807	542	(4,431)	(4,339)	7,238	4,880	12,118
11	March	0	0	1,048	0	(2,245)	(6,038)	3,293	6,038	9,331
12	April	0	0	2,487	0	0	0	2,487	0	2,487
13	Total	3,811	1,635	32,707	66,387	(9,481)	(26,271)	45,999	94,294	140,292
14				add back 10% of the scheduled deliveries=				96,625	97,195	193,819
15						Total ABS Swings =		**142,624**	**191,488**	334,112

Northern Utilities, Inc.
Calculation of Balancing Charge
Analysis of Swings

	Division	UGS Maximum Swings	UGS Sum Positive Swings	Northern UGS Withdrawals	Allocated UGS Withdrawals	Positive UGS Swings as a % of UGS Withdrawals
1	NH	3,532	3,811	4,019,426	1,898,777	0.20%
2	ME	7,580	1,635	4,019,426	2,120,649	0.08%

	Division	LP Max. Swing	LP Sum Positive Swings	LP Tank Capacity	LP Allocated Tank Capacity	LP Swings as a % of Tank Capacity
3	NH	0	0	25,733	12,156	0.00%
4	ME	0	0	25,733	13,577	0.00%

	Division	LNG Max. Swing	LNG Sum Positive Swings	LNG Tank Capacity	LNG Allocated Tank Capacity	LNG Swings as a % of Tank Capacity
5	NH	0	(9,481)	13,750	6,496	145.96%
6	ME	1,418	(26,271)	13,750	7,255	362.13%

	Division	UGS Absolute Value All Swings	UGS Total Absolute Value All Swings	Northern UGS Capacity	Allocated UGS Capacity	Positive UGS Swings as a % of UGS Withdrawals
7	NH	45,999	36,518	293,337	138,572	33.19%
8	ME	94,294	68,023	293,337	154,765	60.93%
9	Total	140,292	104,540		293,337	35.64%

	Division		UGS Max Abs Cum. All Swings		Allocated UGS Capacity	
10	NH		49,355		138,572	47.24%
11	ME		34,012		154,765	52.76%
12	Total		83,367		293,337	**28.42%**

Schedule 19

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2013-2014
Derivation of Class Assignments and Weightings

Basic assumptions:

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

			Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	368	3,680	363	0.7%		988	-
2	RATE B-Resi Htg	21,721	217,210	21,399	39.5%		70	21,329
3	RATE G-40 (R)	9,106	91,060	8,971	16.6%		432	8,539
4	RATE G-50 (Q)	936	9,360	922	1.7%		317	605
5	RATE G-41 (T)	7,907	79,070	7,790	14.4%		302	7,488
6	RATE G-51 (S)	1,531	15,310	1,508	2.8%		231	1,277
7	RATE G-42 (V)	2,061	20,610	2,030	3.8%		38	1,992
8	RATE G-52a (U)	151	1,510	149	0.3%		106	43
9	Special Contract	725	7,245	714	1.3%		725	-
10	RATE T-40	1,721	17,213	1,696	3.1%		118	1,578
11	RATE T-50	345	3,448	340	0.6%		345	-
12	RATE T-41	5,744	57,439	5,659	10.5%		83	5,576
13	RATE T-51	1,113	11,135	1,097	2.0%		756	341
14	RATE T-42	1,254	12,542	1,236	2.3%		10	1,226
15	RATE T-52	272	2,722	268	0.5%		272	-
16	Total	54,955	549,555	54,140	100.0%		4,793	49,993
17			54,955					-
18	Residential Total		220,890	21,761	**40.2%**		1,058	20,703
19	LLF Total		277,934	27,381	50.6%		983	26,398
20	HLF Total		50,731	4,998	9.2%		2,752	2,246
21	Total		549,555	54,140	100.0%		4,793	49,348
22								
23								
24			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
25	Pipeline		2,046,687	11,440	14.91			
26	Storage		14,847,479	16,784	73.72			
27	Peaking		1,437,524	25,916	4.62			
28	Total		18,331,690	54,140	**28.22**	**67.72**		
29								
30								
31								
32			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
33	Pipeline - Baseload		857,400	4,793	14.91			
34	Pipeline - Remaining		1,189,287	6,648	14.91			
35	Storage		14,847,479	16,784	73.72			
36	Peaking		1,437,524	25,916	4.62			
37	Total		18,331,690	54,140	28.22			
38								
39								
40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.			
41	Pipeline - Base	**40.2%**	344,626	1,926	14.91			
42	Pipeline - Remaining	**40.2%**	478,026	2,672	14.91			
43	Storage	**40.2%**	5,967,851	6,746	73.72			
44	Peaking	**40.2%**	577,804	10,417	4.62			
45	Total	**40.2%**	7,368,307	21,761	28.22			

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1	C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.			
2	Pipeline - Base		512,773	2,866	14.91			
3	Pipeline - Remaining		711,261	3,976	14.91			
4	Storage		8,879,628	10,038	73.72			
5	Peaking		859,720	15,499	4.62			
6	Total	**59.8%**	10,963,382	32,379	28.22			
7								
8								
9	LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.			
10	Pipeline - Base		134,973	754	14.91			
11	Pipeline - Remaining		655,483	3,664	14.91			
12	Storage		8,183,280	9,251	73.72			
13	Peaking		792,300	14,284	4.62			
14	Total	**53.3%**	9,766,036	27,953	**29.11**			
15								
16								
17	HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.			
18	Pipeline - Base		377,800	2,112	14.91			
19	Pipeline - Remaining		55,778	312	14.91			
20	Storage		696,349	787	73.72			
21	Peaking		67,420	1,215	4.62			
22	Total	**6.5%**	1,197,347	4,426	**22.54**			
23								
24								
25	Unit Cost		Residential	LLF C&I	HLF C&I			
26								
27	Pipeline		$ 14.91	$ 14.91	$ 14.91			
28	Storage		$ 73.72	$ 73.72	$ 73.72			
29	Peaking		$ 4.62	$ 4.62	$ 4.62			
30	Total		$ 28.22	$ 29.11	$ 22.54			
31	Checktotal		$ 28.22	$ 29.11	$ 22.54			
32								
33							**Storage and Peaking**	
34	Load Makeup		Residential	**LLF C&I**	**HLF C&I**		**LLF C&I**	**HLF C&I**
35								
36	Pipeline		21.13%	**15.81%**	**54.75%**		**NA**	**NA**
37	Storage		31.00%	**33.09%**	**17.78%**		**39.31%**	**39.31%**
38	Peaking		47.87%	**51.10%**	**27.46%**		**60.69%**	**60.69%**
39	Total		100.00%	**100.00%**	**100.00%**			
40								
41								
42	Supply Makeup		Residential	LLF C&I	HLF C&I	Total		
43								
44	Pipeline		40.19%	38.62%	21.18%	100.00%		
45	Storage		40.19%	55.12%	4.69%	100.00%		
46	Peaking		40.19%	55.12%	4.69%	100.00%		

Schedule 20

Provided in Summer 2014 Cost-of-Gas Filing

Schedule 21

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

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 8,421,877
Storage Demand	$ 27,659,740
Peaking Demand	$ 3,384,644
Subtotal Demand	$ 39,466,261
Capacity Release (Credit)	$ (150,697)
Asset Management (Credit)	$ (11,805,500)
Total Net Demand Costs	$ 27,510,064

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	Annual
Design Year Pipeline Sendout	955,303	974,347	907,918	817,518	988,132	800,051	604,773	414,629	362,777	371,552	460,011	718,491	8,375,501
Rank	3	2	4	5	1	6	8	10	12	11	9	7	
% Max Month	96.68%	98.60%	91.88%	82.73%	100.00%	80.97%	61.20%	41.96%	36.71%	37.60%	46.55%	72.71%	
PR	1.60%	0.96%	2.29%	0.35%	1.40%	1.38%	1.83%	0.44%	3.06%	0.08%	0.51%	1.64%	15.54%
CumPR	13.18%	14.14%	11.58%	9.29%	15.54%	8.94%	5.92%	3.58%	3.06%	3.14%	4.09%	7.56%	100.00%
Product and Pipeline Demand Costs	$ 1,109,714	$ 1,190,869	$ 975,091	$ 782,472	$ 1,308,357	$ 752,697	$ 498,380	$ 301,177	$ 257,663	$ 264,462	$ 344,154	$ 636,841	$ 8,421,877

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Storage Injection Volume	-	-	-	-	-	-	53,366	51,644	53,366	53,366	47,595	-	259,337
Design Year Pipeline Sendout	955,303	974,347	907,918	817,518	988,132	800,051	604,773	414,629	362,777	371,552	460,011	718,491	8,375,501
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.1%	11.1%	12.8%	12.6%	9.4%	0.0%	3.0%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,412	$ 33,358	$ 33,043	$ 33,214	$ 32,269	$ -	$ 172,296

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Storage	248,332	755,610	1,014,492	899,456	553,670	17,407	-	-	-	-	-	-	3,488,967
Rank	5	3	1	2	4	6	7	7	7	7	7	7	
% Max Month	24.48%	74.48%	100.00%	88.66%	54.58%	1.72%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	4.55%	6.64%	11.34%	7.09%	7.52%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	37.43%
CumPR	4.84%	19.00%	37.43%	26.09%	12.36%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ 1,338,315	$ 5,254,821	$ 10,352,184	$ 7,215,771	$ 3,419,550	$ 79,099	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,659,740
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,412	$ 33,358	$ 33,043	$ 33,214	$ 32,269	$ -	$ 172,296
TOTAL	$ 1,338,315	$ 5,254,821	$ 10,352,184	$ 7,215,771	$ 3,419,550	$ 79,099	$ 40,412	$ 33,358	$ 33,043	$ 33,214	$ 32,269	$ -	$ 27,832,036

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Peaking Volumes	1,350	56,216	185,462	100,504	1,395	1,393	4,710	1,350	1,395	1,395	1,668	1,395	358,233
Rank	12	3	1	2	9	10	4	11	8	7	5	6	
% Max Month	0.73%	30.31%	100.00%	54.19%	0.75%	0.75%	2.54%	0.73%	0.75%	0.75%	0.90%	0.75%	
PR	0.06%	9.26%	45.81%	11.94%	0.00%	0.00%	0.41%	0.00%	0.00%	0.00%	0.03%	0.00%	67.51%
CumPR	0.06%	9.76%	67.51%	21.70%	0.06%	0.06%	0.50%	0.06%	0.06%	0.06%	0.09%	0.06%	100.00%
Peaking Demand Costs	$ 2,053	$ 330,333	$ 2,284,927	$ 734,462	$ 2,136	$ 2,131	$ 17,012	$ 2,053	$ 2,136	$ 2,136	$ 3,130	$ 2,136	$ 3,384,644

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

1		
2		
3	Pipeline Demand	Schedule 5, PG 1, LN 1
4	Storage Demand	Schedule 5, PG 1, LN 2 & 3
5	Peaking Demand	Schedule 5, PG 1, LN 4 & 5
6	Subtotal Demand	Sum LN 3 : LN 5
7		
8	Capacity Release (Credit)	Schedule 5B, PG 5
9	Asset Management (Credit)	Schedule 5B, PG 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-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual
50	Pipeline & Product Demand	$ 1,109,714	$ 1,190,869	$ 975,091	$ 782,472	$ 1,308,357	$ 752,697	$ 498,380	$ 301,177	$ 257,663	$ 264,462	$ 344,154	$ 636,841	$ 8,421,877
51	Storage Incld Inj Fees	$ 1,338,315	$ 5,254,821	$ 10,352,184	$ 7,215,771	$ 3,419,550	$ 79,099	$ 40,412	$ 33,358	$ 33,043	$ 33,214	$ 32,269	$ -	$ 27,832,036
52	Peaking	$ 2,053	$ 330,333	$ 2,284,927	$ 734,462	$ 2,136	$ 2,131	$ 17,012	$ 2,053	$ 2,136	$ 2,136	$ 3,130	$ 2,136	$ 3,384,644
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ (40,412)	$ (33,358)	$ (33,043)	$ (33,214)	$ (32,269)	$ -	$ (172,296)
54	Less: Capacity Release	$ (30,139)	$ (30,139)	$ (30,139)	$ (30,139)	$ (30,139)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (150,697)
55	Less: Asset Mgmt	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$(1,967,583)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,805,500)
56	Total Demand	$ 452,359	$ 4,778,300	$ 11,614,479	$ 6,734,982	$ 2,732,320	$(1,133,657)	$ 515,392	$ 303,230	$ 259,799	$ 266,598	$ 347,285	$ 638,976	$ 27,510,064

57

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

59		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual
60	**Therms**													
61	Maine	649,566	937,853	1,106,199	957,290	818,364	442,815	335,372	231,013	201,853	207,340	256,254	391,341	6,535,260
62	New Hampshire	555,419	848,319	1,001,673	860,188	724,832	376,035	274,111	184,966	162,319	165,607	205,425	328,545	5,687,439
63	Total	1,204,985	1,786,172	2,107,872	1,817,478	1,543,196	818,850	609,483	415,979	364,172	372,947	461,679	719,886	12,222,699

64	**Percentage of Total**	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual
65	Maine	53.91%	52.51%	52.48%	52.67%	53.03%	54.08%	55.03%	55.53%	55.43%	55.60%	55.50%	54.36%	52.76%
66	New Hampshire	46.09%	47.49%	47.52%	47.33%	46.97%	45.92%	44.97%	44.47%	44.57%	44.40%	44.50%	45.64%	47.24%
67	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

68

69 **Allocation of Demand Costs by Division**

70	Maine	$243,851	$2,508,909	$6,095,211	$3,547,405	$1,448,962	($613,055)	$283,598	$168,398	$144,001	$148,215	$192,760	$347,357	$14,515,613
71	New Hampshire	$208,508	$2,269,391	$5,519,268	$3,187,577	$1,283,358	($520,602)	$231,794	$134,832	$115,798	$118,383	$154,525	$291,619	$12,994,451
72	Total	$ 452,359	$ 4,778,300	$ 11,614,479	$ 6,734,982	$ 2,732,320	$ (1,133,657)	$ 515,392	$ 303,230	$ 259,799	$ 266,598	$ 347,285	$ 638,976	$ 27,510,064

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

74	**Maine**	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	
75	Pipeline & Product Demand	$ 598,208	$ 625,281	$ 511,722	$ 412,138	$ 693,828	$ 407,041	$ 274,237	$ 167,258	$ 142,817	$ 147,028	$ 191,022	$ 346,196	$ 4,516,777	53.63%
76	Storage Incld Injection Fees	$ 721,440	$ 2,759,112	$ 5,432,766	$ 3,800,643	$ 1,813,403	$ 42,775	$ 22,237	$ 18,525	$ 18,315	$ 18,465	$ 17,911	$ -	$ 14,665,593	52.69%
77	Peaking	$ 1,107	$ 173,446	$ 1,199,116	$ 386,851	$ 1,133	$ 1,152	$ 9,361	$ 1,140	$ 1,184	$ 1,187	$ 1,738	$ 1,161	$ 1,778,576	52.55%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ (22,237)	$ (18,525)	$ (18,315)	$ (18,465)	$ (17,911)	$ -	$ (95,453)	55.40%
79	Capacity Release (Credit)	$ (16,247)	$ (15,825)	$ (15,817)	$ (15,875)	$ (15,983)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (79,747)	52.92%
80	Asset Management (Credit)	$ (1,060,657)	$ (1,033,105)	$ (1,032,576)	$ (1,036,352)	$ (1,043,419)	$ (1,064,023)	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,270,132)	53.11%
81	**Total Allocated Demand**	$ 243,851	$ 2,508,909	$ 6,095,211	$ 3,547,405	$ 1,448,962	$ (613,055)	$ 283,598	$ 168,398	$ 144,001	$ 148,215	$ 192,760	$ 347,357	$ 14,515,613	52.76%

82

83	**New Hampshire**	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	
84	Pipeline & Product Demand	$ 511,505	$ 565,588	$ 463,369	$ 370,333	$ 614,529	$ 345,656	$ 224,143	$ 133,919	$ 114,846	$ 117,434	$ 153,132	$ 290,644	$ 3,905,099	46.37%
85	Storage Incld Injection Fees	$ 616,875	$ 2,495,708	$ 4,919,418	$ 3,415,128	$ 1,606,147	$ 36,324	$ 18,175	$ 14,833	$ 14,728	$ 14,749	$ 14,358	$ -	$ 13,166,443	47.31%
86	Peaking	$ 946	$ 156,887	$ 1,085,810	$ 347,611	$ 1,003	$ 979	$ 7,651	$ 913	$ 952	$ 948	$ 1,393	$ 975	$ 1,606,069	47.45%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,175)	$ (14,833)	$ (14,728)	$ (14,749)	$ (14,358)	$ -	$ (76,842)	
88	Capacity Release	$ (13,892)	$ (14,314)	$ (14,322)	$ (14,265)	$ (14,156)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (70,950)	47.08%
89	Asset Management	$ (906,927)	$ (934,478)	$ (935,007)	$ (931,231)	$ (924,165)	$ (903,560)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,535,367)	46.89%
90	**Total Allocated Demand**	$ 208,508	$ 2,269,391	$ 5,519,268	$ 3,187,577	$ 1,283,358	$ (520,602)	$ 231,794	$ 134,832	$ 115,798	$ 118,383	$ 154,525	$ 291,619	$ 12,994,451	47.24%

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

Schedule 22

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	722,652	862,488	688,352	622,370	673,991	534,134	5,413,548	4,103,987
3	Total Storage	12,717	219,365	537,532	429,905	214,525	0	1,414,044	1,414,044
4	Total Peaking	1,350	1,395	153,768	94,904	1,395	3,065	264,157	255,877
5	Subtotal	736,719	1,083,248	1,379,651	1,147,180	889,911	537,199	7,091,749	5,773,908
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	736,719	1,083,248	1,379,651	1,147,180	889,911	537,199	7,091,749	5,773,908
9	Total Firm Pipeline Sendout	722,652	862,488	688,352	622,370	673,991	534,134	5,413,548	4,103,987
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 28,271,161	$ 22,868,912
12	NYMEX Price Used for Forecast	$3.666	$3.830	$3.912	$3.912	$3.877	$3.809		
13	NYMEX Price Used for Update	$3.666	$3.830	$3.912	$3.912	$3.877	$3.809		
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	$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 28,271,161	$ 22,868,912
17									
18	Total Pipeline	$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 28,271,161	$ 22,868,912
19	Total Storage	$ 50,528	$ 871,589	$ 2,132,286	$ 1,704,998	$ 849,861	$ -	$ 5,609,262	$ 5,609,262
20	Total Peaking	$ 9,135	$ 9,824	$ 2,507,626	$ 1,526,964	$ 10,357	$ 21,201	$ 4,139,380	$ 4,085,106
21	Subtotal	$ 4,078,213	$ 5,661,732	$ 8,756,645	$ 6,948,957	$ 4,859,049	$ 2,258,685	$ 38,019,803	$ 32,563,281
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	19	28	32	28	25	15	147	147
26	Average Purchase Price	$ 3.844	$ 4.048	$ 4.132	$ 4.139	$ 4.064	$ 3.955		
27	NYMEX Price Used for Forecast	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809		
28	NYMEX Price Used for Update	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809		
29	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
30	Futures Hedging (Gain)/Loss - Allocate	$ 33,780	$ 61,100	$ 70,540	$ 63,680	$ 46,770	$ 21,860	$ 297,730	$ 297,730
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	-	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809		
35	NYMEX Price Used for Update	$ 3.666	$ 3.830	$ 3.912	$ 3.912	$ 3.877	$ 3.809		
36	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 28,271,161	$ 22,868,912
41	Average Supply Cost ($/MMBtu)	$ 5.561	$ 5.542	$ 5.981	$ 5.972	$ 5.933	$ 4.189		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 28,271,161	$ 22,868,912
46	Total Storage	$ 50,528	$ 871,589	$ 2,132,286	$ 1,704,998	$ 849,861	$ -	$ 5,609,262	$ 5,609,262
47	Total Peaking	$ 9,135	$ 9,824	$ 2,507,626	$ 1,526,964	$ 10,357	$ 21,201	$ 4,139,380	$ 4,085,106
48	Firm Sales Variable Costs Excld Hedge	$ 4,078,213	$ 5,661,732	$ 8,756,645	$ 6,948,957	$ 4,859,049	$ 2,258,685	$ 38,019,803	$ 32,563,281
49	Plus Hedging (Gain)/Loss	$ 33,780	$ 61,100	$ 70,540	$ 63,680	$ 46,770	$ 21,860	$ 297,730	$ 297,730
50	Total Firm Sales Variable Costs	$ 4,111,993	$ 5,722,832	$ 8,827,185	$ 7,012,637	$ 4,905,819	$ 2,280,545	$ 38,317,533	$ 32,861,011

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Attachment NUI-FXW-6, Page 2
3	Total Storage	Attachment NUI-FXW-6, Page 2
4	Total Peaking	Attachment NUI-FXW-6, Page 2
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	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™	Attachment NUI-FXW-6, Page 1
12	NYMEX Price Used for Forecast	Attachment NUI-FXW-10, Page 1
13	NYMEX Price Used for Update	Attachment NUI-FXW-10, 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	Attachment NUI-FXW-6, Page 1
20	Total Peaking	Attachment NUI-FXW-6, Page 1
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)	
25	NYMEX NG Futures Contracts	Attachment NUI-FXW-9
26	Average Purchase Price	Attachment NUI-FXW-9
27	NYMEX Price Used for Forecast	Line 12
28	NYMEX Price Used for Update	Line 13
29	Increase/(Decrease) NYMEX Price	LN 28 - LN 27
30	Futures Hedging (Gain)/Loss - Allocate	(LN 26 - LN 27 - LN 29) * LN 25*10,000
31	Price Triggered NYMEX Contracts (NH Only)	
32	NYMEX NG Futures Contracts	Attachment NUI-FXW-9
33	Average Purchase Price	Attachment NUI-FXW-9
34	NYMEX Price Used for Forecast	Line 12
35	NYMEX Price Used for Update	Line 13
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

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Annual	Winter
51	**Commodity Allocation Factors**								
52	Firm Sales Sendout for Normal Winter, MMBtu								
53		**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	**Winter**
54	Maine	376,594	552,775	709,984	587,378	458,333	282,860	3,624,360	2,967,924
55	New Hampshire	360,148	530,552	669,791	559,933	431,655	254,396	3,467,411	2,806,475
56	Total	736,742	1,083,327	1,379,775	1,147,311	889,988	537,256	7,091,771	5,774,399
57									
58	**Percentage of Total**								
59	Maine	51.12%	51.03%	51.46%	51.20%	51.50%	52.65%	51.11%	51.40%
60	New Hampshire	48.88%	48.97%	48.54%	48.80%	48.50%	47.35%	48.89%	48.60%
61	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
62									
63	**Commodity Allocation by Jurisdiction**								
64	**Maine**								
65	Firm Sales Pipeline Commodity Excld Hedge	$ 2,054,128	$ 2,439,191	$ 2,118,327	$ 1,902,955	$ 2,059,349	$ 1,178,012	$ 14,444,513	$ 11,751,962
66	Hedging (Gains) Losses	$ 17,267	$ 31,177	$ 36,297	$ 32,602	$ 24,086	$ 11,509	$ 152,938	$ 152,938
67	Storage	$ 25,828	$ 444,735	$ 1,097,200	$ 872,892	$ 437,668	$ -	$ 2,878,322	$ 2,878,322
68	Peaking	$ 4,669	$ 5,013	$ 1,290,336	$ 781,745	$ 5,334	$ 11,162	$ 2,125,147	$ 2,098,260
69	Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Total Maine Commodity Costs	$ 2,101,892	$ 2,920,115	$ 4,542,160	$ 3,590,194	$ 2,526,437	$ 1,200,683	$ 19,600,920	$ 16,881,481
71	Maine Inventory Finance Costs	$ 669	$ 1,058	$ 1,410	$ 1,153	$ 846	$ 459	$ 5,593	$ 5,593
72	Total Maine Variable Costs	$ 2,102,561	$ 2,921,173	$ 4,543,570	$ 3,591,346	$ 2,527,283	$ 1,201,142	$ 19,606,513	$ 16,887,074
73	**New Hampshire**								
74	Firm Sales Pipeline Commodity Excld Hedge	$ 1,964,423	$ 2,341,127	$ 1,998,407	$ 1,814,040	$ 1,939,482	$ 1,059,471	$ 13,826,648	$ 11,116,950
75	Hedging (Gains) Losses	$ 16,513	$ 29,923	$ 34,243	$ 31,078	$ 22,684	$ 10,351	$ 144,792	$ 144,792
76	Storage	$ 24,700	$ 426,855	$ 1,035,086	$ 832,106	$ 412,193	$ -	$ 2,730,940	$ 2,730,940
77	Peaking	$ 4,465	$ 4,811	$ 1,217,289	$ 745,219	$ 5,023	$ 10,039	$ 2,014,233	$ 1,986,847
78	New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Total New Hampshire Commodity Costs	$ 2,010,101	$ 2,802,717	$ 4,285,025	$ 3,422,443	$ 2,379,382	$ 1,079,861	$ 18,716,613	$ 15,979,529
80	New Hampshire Inventory Finance Costs	$ 665	$ 1,066	$ 1,398	$ 1,155	$ 829	$ 414	$ 5,527	$ 5,527
81	Total New Hampshire Variable Costs	$ 2,010,766	$ 2,803,782	$ 4,286,423	$ 3,423,599	$ 2,380,212	$ 1,080,275	$ 18,722,140	$ 15,985,057
82	**Northern Utilities**								
83	Firm Sales Pipeline Commodity Excld Hedge	$ 4,018,550	$ 4,780,318	$ 4,116,733	$ 3,716,995	$ 3,998,831	$ 2,237,484	$ 28,271,161	$ 22,868,912
84	Hedging (Gains) Losses	$ 33,780	$ 61,100	$ 70,540	$ 63,680	$ 46,770	$ 21,860	$ 297,730	$ 297,730
85	Storage	$ 50,528	$ 871,589	$ 2,132,286	$ 1,704,998	$ 849,861	$ -	$ 5,609,262	$ 5,609,262
86	Peaking	$ 9,135	$ 9,824	$ 2,507,626	$ 1,526,964	$ 10,357	$ 21,201	$ 4,139,380	$ 4,085,106
87	Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Total Northern Commodity Costs	$ 4,111,993	$ 5,722,832	$ 8,827,185	$ 7,012,637	$ 4,905,819	$ 2,280,545	$ 38,317,533	$ 32,861,011
89	Northern Inventory Finance Costs	$ 1,333	$ 2,123	$ 2,808	$ 2,308	$ 1,675	$ 873	$ 11,120	$ 11,120
90	Total Northern Variable Costs	$ 4,113,326	$ 5,724,955	$ 8,829,993	$ 7,014,945	$ 4,907,495	$ 2,281,417	$ 38,328,653	$ 32,872,131
91									

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	NUI-CAK-3, LN 33/10
55	New Hampshire	Company Analysis
56	Total	LN 54 + LN 55
57		
58	**Percentage of Total**	
59	Maine	LN 54 / LN 56
60	New Hampshire	LN 55 / LN 56
61	Total	LN 59 + LN 60
62		
63	**Commodity Allocation by Jurisdiction**	
64	**Maine**	
65	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 59
66	Hedging (Gains) Losses	LN 30 * LN 59
67	Storage	LN 46 * LN 59
68	Peaking	LN 47 * LN 59
69	Maine Interruptible	LN 42
70	Total Maine Commodity Costs	Sum LN 65 : LN 69
71	Maine Inventory Finance Costs	LN 112
72	Total Maine Variable Costs	LN 70 + LN 71
73	**New Hampshire**	
74	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 60
75	Hedging (Gains) Losses	LN 30 * LN 60
76	Storage	LN 46 * LN 60
77	Peaking	LN 47 * LN 60
78	New Hampshire Interruptible	LN 43
79	Total New Hampshire Commodity Costs	Sum LN 74 : LN 78
80	New Hampshire Inventory Finance Costs	LN 117
81	Total New Hampshire Variable Costs	LN 79 + LN 80
82	**Northern Utilities**	
83	Firm Sales Pipeline Commodity Excld Hedge	LN 65 + LN 74
84	Hedging (Gains) Losses	LN 66 + LN 75
85	Storage	LN 67 + LN 76
86	Peaking	LN 68 + LN 77
87	Northern Interruptible	LN 69 + LN 78
88	Total Northern Commodity Costs	LN 70 + LN 79
89	Northern Inventory Finance Costs	LN 71 + LN 80
90	Total Northern Variable Costs	LN 88 + LN 89
91		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

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

95									
96	**Col A**	**Col B**	**Col C**	**Col D**	**Col E**	**Col F**	**Col G**	**Col N**	**Col O**
97									
98	**Inventory Finance Charge**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Annual**	
99	Storage	$ 1,338	$ 1,338	$ 1,083	$ 598	$ 184	$ -	$ 9,318	
100	Peaking	$ 148	$ 157	$ 153	$ 149	$ 153	$ 155	$ 1,803	
101	Total	$ 1,486	$ 1,495	$ 1,236	$ 748	$ 337	$ 155	$ 11,120	
102									
103	**Inventory Finance Charge Allocation by Jurisdiction**								
104	Maine	$ 760	$ 763	$ 636	$ 383	$ 174	$ 82	$ 5,593	
105	New Hampshire	$ 726	$ 732	$ 600	$ 365	$ 163	$ 73	$ 5,527	
106	Total	$ 1,486	$ 1,495	$ 1,236	$ 748	$ 337	$ 155	$ 11,120	
107									
108	**Inventory Finance Charge Allocation by Month**								
109	**Maine**								
110	Firm Sales Normal Remaining Sendout	298,539	472,118	629,327	514,526	377,676	204,804	2,496,990	2,496,990
111	Monthly % Sendout of Total Winter	11.96%	18.91%	25.20%	20.61%	15.13%	8.20%	100.00%	100.00%
112	ME Allocated Inventory Finance Charge	$ 669	$ 1,058	$ 1,410	$ 1,153	$ 846	$ 459	$ 5,593	$ 5,593
113									
114	**New Hampshire**								
115	Firm Sales Normal Remaining Sendout	278,097	445,766	585,005	483,352	346,869	173,127	2,312,214	2,312,214
116	Monthly % Sendout of Total Winter	12.03%	19.28%	25.30%	20.90%	15.00%	7.49%	100.00%	100.00%
117	NH Allocated Inventory Finance Charge	$ 665	$ 1,066	$ 1,398	$ 1,155	$ 829	$ 414	$ 5,527	$ 5,527

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	Attachment NUI-CAK-7 - 'Carrying Costs'
100	Peaking	Attachment NUI-CAK-7 - '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	Attachment NUI-CAK-3, LN 80/10
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 Col N
112	ME Allocated Inventory Finance Charge	LN 104 Col N * LN 111
113		
114	**New Hampshire**	
115	Firm Sales Remaining Sendout	Company Analysis
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Schedule 23

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

		Winter	Summer	Annual	
1	Demand	$ 9,610,249	$ 931,944	$ 10,542,193	Schedule 1A, LN 80
2	Commodity	$ 15,985,057	$ 2,737,084	$ 18,722,140	Schedule 1B, LN 43
3	Total	$ 25,595,305	$ 3,669,028	$ 29,264,334	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	27,891,158	6,566,792	34,457,951	Schedule 10B, LN 12
6	Forecasted Residential Sales (Therms)	13,894,351	3,167,323	17,061,674	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Annual**	
8	Average Demand Rate	$0.3446	$0.1419		LN 1 / LN 5
9	Average Commodity Rate	$0.5731	$0.4168		LN 2 / LN 5
10	Average Rate	$0.9177	$0.5587		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Annual**	
13	Demand Costs Allocated To Residential per SMBA	$ 4,880,017	$ 461,947	$ 5,341,964	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 4,787,473	$ 449,443	$ 5,236,916	LN 8 * LN 6
15	**Demand Reallocation:**	$ 92,543	$ 12,504	$ 105,047	LN 13 - LN 14
16	**HLF Allocation**	$ 10,379	$ 3,288	$ 13,667	LN 15 / LN 20
17	**LLF Allocation**	$ 82,165	$ 9,216	$ 91,381	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	11.21%	26.30%		Schedule 10A, LN 173
21	LLF	88.79%	73.70%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 7,962,351	$ 1,320,162	$ 9,282,512	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 7,963,168	$ 1,320,140	$ 9,283,309	LN 9 * LN 6
25	**Commodity Reallocation:**	$ (818)	$ 22	$ (796)	LN 23 - LN 24
26	**HLF Allocation**	$ (122)	$ 9	$ (113)	LN 25 * LN 30
27	**LLF Allocation**	$ (696)	$ 12	$ (683)	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	14.91%	42.15%		Schedule 10C, LN 143
31	LLF	85.09%	57.85%		Schedule 10C, LN 144

Schedule 24

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

NU Short-Term Debt Limit Calculation (11/1/13 - 10/31/2014)

Fuel Financing Purposes		
NU ME winter gas costs	23,826	
NU NH winter gas costs	23,893	
Total	47,719	
30% of total winter gas costs	14,316	(a)
Non-Fuel Financing Purposes		
Estimated net utility plant @ 12/31/13 before plant acquisition adjustment	277,062	
15% of Net Utility Plant	41,559	(b)
Short-Term Debt Limit		
Short Term Debt Limit	**55,875**	(a) + (b)

Schedule 25

Northern Utilities, Inc., New Hampshire Division
Determination of PNGTS Refund
Effective: November 2013 - October 2014

1	PNGTS Refund - Principal	$540,813	LN 3 - LN 2
2	PNGTS Refund - Interest	$6,816	Schedules 5C & 5B, PG 6
3	Total PNGTS Refund	$547,629	Schedule 5B, PG 6
4	Estimated Interest Expense - Northern	$8,533	PG 2, LN 9
5	Total	$556,163	LN 3 + LN 4
6	Total DTHs: (November 13 - October 14)	34,457,951	FORECAST
7	Demand Refund Rate ($/CCF)	$0.0161	LN 5/ LN 6

Northern Utilities, Inc.
New Hampshire Division
Schedule 25
Page 2 of 2

Effective: November 2013 - October 2014

		Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Total	Total	Total
		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-13 to Apr-13	Apr-13 to Oct-13	Nov-12 to Oct-13
1	Beginning Balance	$0	$548,095	$548,996	$549,928	$550,832	$551,768	$552,705	$495,943	$411,821	$305,237	$216,086	$147,329	$106,823	$85,612	$70,542	$57,382	$43,607	$28,380			
2	PNGTS Refund with Interest	$547,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0			
3	Firm Sales (DTHs)	$0	$0					3,579,105	5,272,786	6,656,691	5,564,807	4,289,774	2,527,995	1,327,606	944,011	823,915	860,734	949,421	1,661,106	27,891,158	6,566,792	34,457,951
4	Refund	$0	$0					$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161			
5	Refund Amount	$0	$0					$57,624	$84,892	$107,173	$89,593	$69,065	$40,701	$21,374	$15,199	$13,265	$13,858	$15,286	$26,744	$449,048	$105,725	$554,773
6	Ending Balance - excl. interest	$547,629	$548,095	$548,996	$549,928	$550,832	$551,768	$495,081	$411,051	$304,648	$215,644	$147,021	$106,629	$85,449	$70,414	$57,277	$43,524	$28,321	$1,637			
7	Average Monthly Balance	$273,815	$548,095	$548,996	$549,928	$550,832	$551,768	$523,893	$453,497	$358,235	$260,441	$181,554	$126,979	$96,136	$78,013	$63,909	$50,453	$35,964	$15,009			
8	Interest Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%			
9	Computed Interest	$465	$901	$933	$904	$936	$937	$861	$770	$589	$442	$308	$195	$163	$128	$105	$83	$59	$25	$6,707	$1,826	$8,533
10	Ending Balance	$548,095	$548,996	$549,928	$550,832	$551,768	$552,705	$495,943	$411,821	$305,237	$216,086	$147,329	$106,823	$85,612	$70,542	$57,382	$43,607	$28,380	$1,661			